



Department of Energy
Washington, DC 20585

Order No. 202-26-19

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (“Schahfer”) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).³ Unit 17 and Unit 18 began operations in 1983 and 1986, respectively. Unit 17 and Unit 18 were both slated to cease operations in December 2025.⁴

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer remain in operation for 90 days, through March 23, 2026. This order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁴ As coal-fired facilities, it would be difficult for Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

demand or low generation resource output.⁵ I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁶ I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.⁷

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”⁸ Additionally, the LTRA notes that “[t]he departure of MISO’s coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years.”⁹

Second, MISO’s year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction (PRA)) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹ MISO noted that over 60% of all “MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.¹²

⁵ See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

⁶ See, e.g., *id.* at 1–4.

⁷ See, e.g., *id.* at 5.

⁸ NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁹ *Id.* at 44.

¹⁰ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

¹¹ *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

¹² *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-12 continue, both in the near and long term.¹³ The production of electricity from Schahfer will continue to be critical to maintain reliability in MISO. MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO’s North and Central Regions due to generation outages, high demand, and transfer capability limits.¹⁴ From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.¹⁵

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”¹⁶ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.¹⁷

¹³ Further, as noted in Order No. 202-25-12, as a coal-fired facility, it would be difficult for Schahfer to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If NIPSCO were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-12 at 1.

¹⁴ *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁵ U.S. Dep’t of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁶ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

¹⁷ *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁸ In a section of that report entitled, “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹⁹ These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁰ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²¹ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²² This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²³ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²⁴ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²⁵ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”²⁶

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves

¹⁸ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹⁹ *Id.* at 12.

²⁰ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²¹ *Id.* at 7.

²² *Id.* at 8.

²³ *Id.* at 43.

²⁴ *Id.* at 15.

²⁵ *Id.*

²⁶ *Id.*

in above-normal conditions.”²⁷ These findings were echoed in NERC’s 2024–2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²⁸

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁹

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁰ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.³¹ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.³² It also projected similar results for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.³³

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.³⁴

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

²⁷ NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

²⁸ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

²⁹ MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

³⁰ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³¹ *Id.* at 2.

³² *Id.* at 7.

³³ *Id.* at 9.

³⁴ *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³⁵

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Schahfer.³⁶

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.³⁷ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.³⁸ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.³⁹ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-12 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and

³⁵ *Id.*

³⁶ See *Electricity*, Energy Information Administration, Indiana Analysis, <https://www.eia.gov/states/in/analysis>.

³⁷ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁸ *Id.* P 84.

³⁹ See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) (“With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

extraordinary threat to our Nation’s economy, national security, and foreign policy.”⁴⁰ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”⁴¹ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴²

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴³ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators—including MISO itself—have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴⁴

⁴⁰ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴¹ *Id.*

⁴² Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴³ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf>.

⁴⁴ *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), <https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/>

Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁴⁵ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁴⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”⁴⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through June 21, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. From March 24, 2026, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the

files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

⁴⁵ *Id.* at 6.

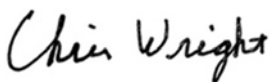
⁴⁶ *Id.* at 7.

⁴⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 have operated in compliance with the allowances contained in this Order.
- C. All operation of Schahfer must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.
- H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner



Department of Energy
Washington, DC 20585

Order No. 202-26-20

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW.³ Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.⁴

Order No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. This order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.⁵ I determined that the continued operation of

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁴ As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling Unit 2 or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁵ See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁶ I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.⁷

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”⁸ Additionally, the LTRA notes that “[t]he departure of MISO’s coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years.”⁹

Second, MISO’s year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹ MISO noted that over 60% of all “MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.¹²

⁶ See, e.g., *id.* at 1–4.

⁷ See, e.g., *id.* at 5.

⁸ NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁹ *Id.* at 44.

¹⁰ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

¹¹ *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

¹² *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-13 continue, both in the near and long term.¹³ The production of electricity from Culley Unit 2 will continue to be critical to maintain reliability in MISO. MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO’s North and Central Regions due to generation outages, high demand, and transfer capability limits.¹⁴ From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day, providing vital generation capacity to the region.¹⁵

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”¹⁶ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects risk of loss of load in the winter and spring seasons; although not as high as in the summer or fall, losses will nevertheless increase over time.¹⁷

¹³ Further, as noted in Order No. 202-25-13, as a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If CenterPoint Energy were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-13 at 1.

¹⁴ *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁵ U.S. Dep’t of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁶ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

¹⁷ *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁸ In a section of that report entitled, “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹⁹ These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁰ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²¹ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²² This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²³ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²⁴ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²⁵ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”²⁶

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves

¹⁸ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final+504018.pdf>.

¹⁹ *Id.* at 12.

²⁰ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²¹ *Id.* at 7.

²² *Id.* at 8.

²³ *Id.* at 43.

²⁴ *Id.* at 15.

²⁵ *Id.*

²⁶ *Id.*

in above-normal conditions.”²⁷ These findings were echoed in NERC’s 2024–2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to that of the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²⁸

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁹

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reports the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁰ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.³¹ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.³² Similar results were projected for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.³³

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.³⁴

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

²⁷ NERC, *2023 – 2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

²⁸ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

²⁹ MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20250529_Corrections694160.pdf.

³⁰ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³¹ *Id.* at 2.

³² *Id.* at 7.

³³ *Id.* at 9.

³⁴ *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³⁵

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Culley.³⁶

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.³⁷ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.³⁸ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.³⁹ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-13 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and

³⁵ *Id.*

³⁶ See *Electricity*, Energy Information Administration, Indiana Analysis, <https://www.eia.gov/states/in/analysis>.

³⁷ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁸ *Id.* P 84.

³⁹ See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) (“With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

extraordinary threat to our Nation’s economy, national security, and foreign policy.”⁴⁰ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”⁴¹ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴²

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴³ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators — including MISO itself — have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴⁴

⁴⁰ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴¹ *Id.*

⁴² Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴³ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf>.

⁴⁴ *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), <https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/>

Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁴⁵ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁴⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”⁴⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through June 21, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. From March 24, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this

files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

⁴⁵ *Id.* at 6.

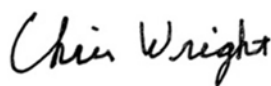
⁴⁶ *Id.* at 7.

⁴⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.
- C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.
- H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners

Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator

Order Nos. 202-25-12, 202-25-13

**MOTION TO INTERVENE AND PETITION FOR REHEARING
OF THE STATES OF MINNESOTA AND ILLINOIS AND THE PEOPLE OF THE STATE
OF MICHIGAN**

Pursuant to section 202 (c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 8251, the States of Minnesota and Illinois and the People of the State of Michigan (“the States”), move to intervene and petition for rehearing of the Department of Energy’s (“DOE”) orders 202-25-12 (Schahfer) and 202-25-13 (Culley Unit 2) (together, “Orders”),¹ directing the Midcontinent Independent System Operator (“MISO”), Northern Indiana Public Service Company (“NIPSCO”) and CenterPoint Energy (“CenterPoint”) to take all measures necessary to ensure that the coal-burning Schahfer plant (“Schahfer”) and coal-burning Culley Unit 2 (“Culley”) are “available to operate” and “to take every step to employ economic dispatch” of those resources. The Orders are in effect from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, until 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026,.

Pursuant to the Federal Power Act (“the Act”) and Department procedures applying it to petitions for rehearing, the States hereby file this timely request for rehearing of DOE’s Schahfer and Culley Orders. Some of the States have already sought both rehearing and review of three similar orders that the

¹ All Exhibits are lettered and attached; to be submitted in separate serial emails to the DOE’s AskCR <askcr@hq.doe.gov> account.

DOE issued to the J.H. Campbell Plant in West Olive, Michigan. The Schahfer and Culley Orders perpetuate the same errors underlying the Campbell Order, perpetuating DOE's flawed analyses, faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO"), and unlawful directives—all of which together harm the States.

The Schahfer and Culley Orders exceed DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue such orders, the Schahfer and Culley Orders are not rationally related to meet the purported need. They should be rescinded.

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MOTION TO INTERVENE

The States² move to intervene in this proceeding and thereby to become parties for purposes of Section 3131 of the Act, 16 U.S.C. § 8251. The States have an interest in and are aggrieved by the subject orders (Exs. A, B) in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U. S. ____ (2025) (slip op., at 3–8) (defining an “adversely affected or aggrieved” party within the APA as “anyone even ‘arguably within the zone of interests to be protected or regulated by the statute . . . in question.’” (quoting *Association of Data Processing Service Organizations, Inc. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities regulated by the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator (“ISO”) in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the “air traffic controller” for the grid in its territory,³ meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

² See Minn. Stat. § 8.01 (“The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.”).

³ “Meet MISO,” <https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/> (last visited June 23, 2025).

On December 23, 2025, the DOE issued the Schahfer Order (202-7-12) to MISO and NIPSCO. Ex. A. On December 23, 2025, the DOE issued the Culley Order (202-7-13) to MISO and CenterPoint. Ex. B. Both orders were issued pursuant to section 202(c) of the Federal Power Act. *See* 16 U.S.C. § 824(c)(1).

The Orders direct MISO, in coordination with NIPSCO (Schahfer) and CenterPoint (Culley), the respective operators of the plants, to ensure that the plants remain available for operation during the period of the order (December 23, 2025, through March 23, 2026). *Id.*

These eleventh-hour Orders disrupted a longstanding planning sequence handled by state authorities and submitted to MISO, which included plans to retire the Schahfer and Culley Unit 2 plants on December 31, 2025.⁴ Ex. C (NIPSCO IRP). The integrated resource planning process already accounted for increased need and slated adequate generation to meet requirements. Ex. C at 6 (“Thus, the 2024 IRP was structured to ensure a robust assessment of the type of resources needed to respond to emerging market conditions and future portfolio retirements.”). As recently as October 29, 2025, NIPSCO recommitted to Indiana regulators its plan to retire Schahfer Units 17 and 18 in accordance with its January 2023 submission to MISO, which MISO approved in February 2023. Ex. E.

All three units at these two plants were slated for retirement because they are old and in disrepair, and the units experienced deferred maintenance leading up to their planned retirement; they cannot be economically operated and require significant overhaul and upkeep costs to stay running. For example, CenterPoint explained that the Culley Unit 2 retirement was part of a plan

⁴ *See* Consumers Energy, “2021 Clean Energy Plan,” <https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf> (last accessed June 23, 2025).

that would save ratepayers \$80 million. Ex. D. And upon announcing the retirement of the Schahfer units, NIPSCO touted the cost-savings of transitioning away from coal as a fuel source. Ex. F.

Adverse Effects

The States will be adversely affected by the Orders directed to the Schahfer and Culley coal units in many of the same ways that they were harmed by the Campbell Orders that they have separately requested rehearing or otherwise challenged.

The Schahfer and Culley Orders prevent the planned retirement of the respective plants with consequent negative impacts on the States.

First, households and businesses in the States, and the States as consumers in their own right, will pay higher electricity bills as a result of the Orders' imposition of costs and cost-recovery to the States. By ordering the utilities to take all steps necessary to make the coal plants available and ordering MISO to take all steps necessary for the plants to provide economic dispatch, costs are already being incurred and more costs will continue to be generated.

Notably, the age of the units is concerning for costs, especially given the cost-savings assessments of the retirement plans. The Orders will likely require at least a portion of capital expenditures and major maintenance costs, which will drive up costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Orders provide that cost recovery is available through Federal Energy Regulatory Commission ("FERC") proceedings. Exs. A-B at ¶¶E. The operators have already initiated cost recovery complaints before FERC that, if approved, will impact ratepayers on the States.

Second, the States will suffer environmental harms as a result of the Order. The coal operations at Schahfer and Culley are a significant source of particulate matter, nitrogen oxides,

sulfur oxides, and carbon dioxide,⁵ among other pollutants. By extending the operations of the plants beyond their planned retirement dates, the Orders increase the amount of pollution emitted in the region, causing harm to the public health and welfare.⁶ The States of Minnesota, Illinois, Michigan, and Wisconsin share the upper Midwest region and Great Lakes environment with Indiana. Depending on weather, air emissions in Indiana impact conditions in the States. Further, the States have an interest in the Great Lakes ecosystem into which pollutants from coal-burning power plants such as mercury are deposited. Such pollution is harmful to state economies including fisheries and recreation, human health, and the environment in general. The Schahfer plant is immediately southeast of Chicago, Illinois, and near the shore of Lake Michigan. The Culley Plant is located on the shore of the Ohio River immediate upstream of Illinois's southern border. Thus, the States have an economic, public health, and ecological interest in protecting their environment and natural resources from unnecessary pollution emanating from the Schahfer and Culley plants. The States are harmed because the Orders result in the unnecessary consumption of coal fuel that generates such pollution.

Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States by imposing significant additional costs for responsive actions, disaster recovery, and resiliency programs. Increased emissions threaten state climate goals and the States' ability to comply with federal and state air pollution requirements.

⁵ See *In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

⁶ See *Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.*

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.⁷ Each of Minnesota’s top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.⁸ Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.⁹ These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.¹⁰ Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures. The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal disaster declarations for large parts of the state.¹¹ From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.¹² The “Lost Winter” of 2023-2024 was the

⁷ Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.

⁸ *Id.*

⁹ *Id.*

¹⁰ *Id.*

¹¹ “Extreme Rainfall Drenches Northeastern Minnesota,” Minnesota Department of Natural Resources, <https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024>; “Extreme Rain and Flooding in Southern Minnesota, June 20-22,” Minnesota Department of Natural Resources, (August 9, 2024), <https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html>; “Disaster information,” Minnesota Department of Public Safety, <https://dps.mn.gov/divisions/hsem/em-resources/disaster-information> (last visited June 23, 2025).

¹² “Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI),” <https://www.ncei.noaa.gov/access/billions/state-summary/MN>.

warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota’s recreational economy.¹³ These impacts will continue, and emissions from the Schahfer and Culley coal operations will contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois’ farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.¹⁴ In other years, extreme precipitation has threatened Illinois’ agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose revenue.¹⁵ Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois’ 102 counties and the state logged 142 tornadoes—a new annual record.¹⁶ These storms included a July 15, 2024 “derecho” that produced 100 mile-per-hour winds and 48 separate tornados.¹⁷ In the

¹³ *Id.*

¹⁴ Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), <https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/> (last visited May 23, 2025).

¹⁵ University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).

¹⁶ Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), <https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/> (last visited May 23, 2025).

¹⁷ National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 “double derecho” and a March 2023 storm.

As demonstrated by the attached declarations of Douglas Jester, Exhibits DD and EE, the Schahfer and Culley coal burning units—if continued to operate—would have significant monetary and environmental impacts on the States. The operation of Schahfer will result in approximately 1.0-1.9 deaths and \$15.8 million to \$29 million monetized health effects across Illinois, Michigan, and Minnesota. Ex. DD at ¶22 (*citing* EPA’s the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)). And the operation of Culley will result in approximately 0.16-0.325 deaths and \$2.12 million to \$4.23 million monetized health effects across Illinois, Michigan, and Minnesota. Ex. EE (same). The continued operation of the Schahfer and Culley coal units will have a net harmful effect on public health in Illinois, Michigan, and Minnesota. Ex. DD at ¶ 26; Ex. EE at ¶ 26.

Moreover, the States have an interest given their primary responsibility for resource planning and ensuring that there will be adequate and reliable electricity generation. The processes that States employ to ensure reliability—which takes into account planned retirements, new generation projects, transmission infrastructure, and meet consumer demand—are both sophisticated and robust. The Orders harm the States by usurping the traditional role that states play in generation planning and resource adequacy.

PETITION FOR REHEARING

he%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). See also David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by ‘Ring of Fire’, WBEZ CHICAGO, available at <https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15> (last accessed May 23, 2025)

I. Overview and Concise Statement of Error

The challenged Orders compound the error of the DOE's Campbell Orders in that they declare an emergency based on a shortage of electric energy generation when there is no emergency. Even if there were an emergency, the Orders impose several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE had the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The Orders are premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025 through 2032.

The Orders misconstrue the source material on which they rely and still conclude only that there is a possibility of shortfalls. But they do not cite or rely on any evidence that there is any likelihood or probability that any shortfall will occur during the relevant timeframe of the Orders (December 23, 2025, through March 23, 2026).

The Orders conclude that the evidence collected (and discussed below) supports their issuance. They contend that the purported emergency will continue in the near term and is likely to continue in subsequent years. It declares—without any evidence identifying an emergency in December-March timeframe—that the alleged emergency “could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.” Exs. A at 4, B at 5 (emphasis added). They then order that MISO and the relevant utility shall take “all measures necessary to ensure that” the plants are “available to operate.” *Id.* at ¶A. And MISO must “take every step to employ economic dispatch” of the plants “to minimize cost to ratepayers.” *Id.* Further, they order that the plants operate according to times as determined by MISO. Importantly, the orders prohibit the plants from being considered a capacity resource. *Id.* at ¶ G.

These Orders were issued in error. The DOE did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency in general, be it far into the future or even in the December 2025-March 2026 timeframe.

The Orders start from the proposition that there is only a “potential” for insufficient capacity that “could” result in a need for mitigation, which does not present an actual existing or imminent emergency. *Id.* at 2. And in the same discussion, the Orders acknowledge that there is actually a projected surplus in the summer of 2026. *Id.* at 3 (citing MISO Survey, attached as Ex. G). But Section 202(c)’s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. These Orders, however, require the plants to be “available to operate.” Nothing in section 202(c) grants DOE authority to order a plant be available to operate without any demonstrated need during the timeframe of the order identified by the states with primary resource planning authority, the utility operating the resource, or grid operator responsible for forecasting and coordinating adequate and reliable supply.

Even if an emergency did exist during the timeframe of the orders and DOE had the legal authority to issue them, directing the plants to participate in the bidding market using economic dispatch would not rationally “best” meet the purported need because there is no evidence the coal plants can reasonably address any given future emergency need; this is because emergency responses do not require economic evaluation, and because the coal plants take so long to ramp up. The Orders should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission¹⁸ has authority to issue an order:

[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order “temporary connections of facilities” and “generation, delivery, interchange, or transmission of electric energy” that, in the Commission’s “judgment will best meet the emergency and serve the public interest.” *Id.* The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or

¹⁸ The “Commission” refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over “the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*).” 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE “the function of the Federal Power Commission, or of the members, officers, or components thereof” except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC’s authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC’s (not DOE’s) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id.* Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define “emergency,” as:

an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected “entity” to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned *as meeting a specific inadequate power supply situation.*

10 C.F.R. § 205.371¹⁹ (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for the Orders’ declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on evidence that did not identify any likelihood or probability that there would be a shortfall during the relevant timeframe of the Orders’ requirements—December 23, 2025, to March 23, 2025. Further, DOE failed to consider substantial countervailing evidence, including the MISO States’ Integrated Resource Plans and MISO’s assessment of surplus capacity for the summer of 2026. The Orders fail to identify any reasoned basis for concluding an actual emergency exists or is imminent, much less one that will occur between December 23,

¹⁹ DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act’s transfer of emergency responsibilities to the Secretary of Energy.

2025, and March 23, 2026. Instead, the Orders explicitly contemplate longer-term resource planning for the summer of 2027 and even into the 2030 timeframe—more than a year after the term of the Orders expires. Exs. A-B at 2-3.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply situation. Did DOE exceed this authority where the Orders are based on the nonspecific possibility that such a situation might occur over a period of several months—or in the 2027-2030 timeframe, well outside of the Orders’ applicability?

Yes. An actual “emergency” is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to “a specific inadequate power supply situation.” 10 C.F.R. § 205.371. The Orders do not address any sudden occurrence needing imminent response, nor do they identify any actual and specific insufficient supply situation. Instead, the Orders focus on vague non-summer needs and the potential for shortfalls several years away. The Orders are not directed to any emergency at all, much less one occurring in the December 23, 2025-March 23, 2026 timeframe. They are contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the “generation, delivery, interchange, or transmission of electric energy.” Did DOE exceed this authority where the Orders require the coal plants to take steps to be “available” to generate electricity and require MISO to employ economic dispatch?

Yes. DOE’s emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because the Orders do not adhere to the types of actions allowed under section 202(c)(1), they are without authority and contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue Orders that set no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Orders do not establish any limited hours for operation, instead deferring to MISO. The Orders also do not meaningfully take steps to minimize adverse environmental impacts. Because the Orders do not set any specific hours the plants must run, and do not meaningfully minimize adverse environmental impacts, the Orders violate the requirements of section 202(c)(2). They are without authority and contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Orders directly compel plants slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends “only to those matters which are not subject to regulation by the States.” 16 U. S. C. § 824(a). States retain jurisdiction “over facilities used for the generation of electric energy.” 16 U.S.C. § 824(b)(1). DOE’s Orders exceed its authority by contradicting existing resource plans. It also exceeds DOE’s authority by purporting to engage in long-term resource planning for the years 2027-2030, which is a role reserved to the states. For both of these reasons, the Orders are contrary to law.

Issue F: Even if DOE were correct that an emergency exists and that it had the authority to issue the Orders, will the Orders’ requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to “best” meet the specific emergency. 16 U.S.C. § 824a(c). The Orders’ specific requirement for MISO to take steps to effectuate “economic dispatch” of the respective plants is not rationally related to the

emergency the Orders purport to address. The Orders do not explain how keeping the coal plants available to run will meet any particular need when MISO has adequate resources at its disposal without the output of the subject plants. The Orders, therefore, are without substantial evidence and lack reasoned decision-making.

Issue G: Federal law prohibits agencies from prejudging the outcome of an action. Did the Secretary of Energy and the federal administration improperly prejudge the need for the Orders to the Schahfer and Culley coal units?

Yes. As evidenced by public statements, the purported emergency is pretext for an improperly-prejudged outcome to preserve coal as a fuel for electrical generation.

IV. MISO’s Robust Capacity and Planning Projections, in Tandem with State-Level Regulatory Processes, are Adequate to Ensure Reliability.

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.²⁰ 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.²¹ MISO also

²⁰ MISO, *Fact Sheet* (July 2024), available at <https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet>.

²¹ MISO, *Electric Grid 101*, available at <https://www.misoenergy.org/meet-miso/grid-operations-basics>

works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.²² MISO uses advanced modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.²³

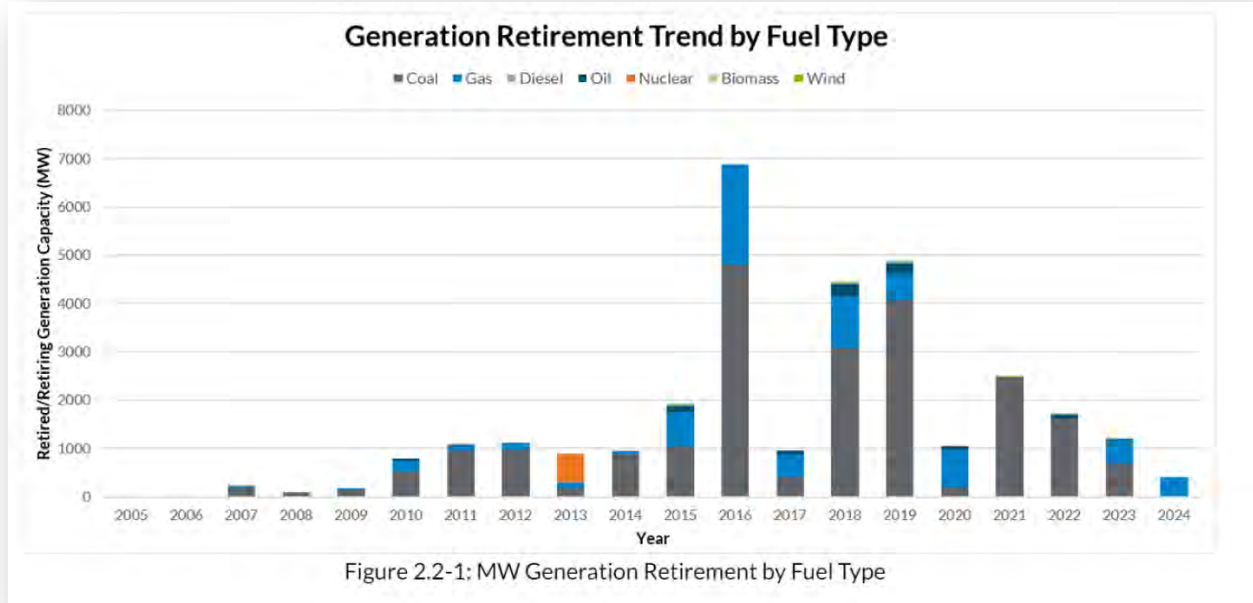
MISO planned for adequate capacity in 2025 and 2026—the timeframe of the Orders: MISO’s Planning Resource Auction [“PRA”] for the 2025-2026 Planning Year “demonstrated sufficient capacity for all zones within the MISO Region.” Ex. H at 2. It reports: “it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order.*” *Id.* (emphasis added). And it goes on to describe its confidence that it has already ensured “sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year.” *Id.*

The long-planned retirement of the plants subject to the Orders is not an impediment to reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating

²² MISO, *Interregional Coordination*, available at <https://www.misoenergy.org/planning/interregional-coodination/>; see also MISO, Historical Net Scheduled Interchange (NSI), at <https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/> (data found under “Summary” Market Reports).

²³ MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

units.²⁴ That trend is shown below in the bar graph (from MISO’s 2023 Transmission Expansion Plan Report,²⁵ Ex. I at 35), which displays the retired capacity by generation type over time:



Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id.* at 34-35. The sufficiency of MISO’s planning was recently affirmed in MISO’s Answer to NIPSCO’s Complaint in FERC Docket EL26-38-000, with the grid operator stating that:

²⁴ See also MISO, *Approved Generator Retirements (Public) as of June 28, 2024* (“Approved Retirements 2024”), [https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_\(Public\)_2024-06-28.pdf](https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

²⁵ MISO, *2023 Transmission Expansion Plan*, available at <https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf>.

[I]t is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025- 2026 Planning Year reflects the diligent efforts of MISO’s members, Market Participants, Relevant Electric Retail Regulatory Authorities (“RERRA”) and the Federal Energy Regulatory Commission (“FERC”) to establish policies and processes that address both immediate and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.²⁶

The sufficiency of resource planning here has further been subject to review through Indiana’s Integrated Resource Plan (IRP) processes; both NIPSCO and Centerpoint have acknowledged that the planned retirements of the coal units at issue were subject to IRP review before the Indiana Utility Regulatory Commission.²⁷ Indiana’s statute governing the contents of IRP submissions requires that utilities include a breadth of analysis and forecasting as to resource planning.²⁸ Utilities in Indiana’s MISO transmission area are further required to submit to the IURC their annual resource adequacy assessment as reported to MISO.²⁹ Thus, through these

²⁶ Answer of the Midcontinent Independent System Operator, Inc., FERC Docket EL26-36-000 at 2 (January 20, 2026).

²⁷ *See, e.g.*, Complaint and Request for Fast Track Processing of Northern Indiana Public Service Company LLC, FERC Docket EL26-36-000 at 7 (December 29, 2025) (“NIPSCO’s 2021 Integrated Resource Plan (“IRP”) included a retirement analysis to assess retirement dates for different generating units of its existing generation fleet”); *See also, e.g.*, Complaint Requesting Fast Track Processing, FERC Docket EL26-38-000 at 9 – 10 (January 5, 2026).

²⁸ *See*, 170 Ind. Admin. Code 4-7-4 (The required “[i]ntegrated resource plan contents” including, to provide just a few examples of many, “[a]t least a twenty (20) year future period for predicted or forecasted analyses,” “[a]n analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule,” and “[a] description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.”).

²⁹ *See*, 170 Ind. Admin. Code 4-7-2.3(a).

processes, extensive planning for the retirement of the Schahfer and Culley units at issue has been conducted,³⁰ in conjunction with the grid-operator’s resource adequacy planning.

V. Argument

A. **The Orders are not supported by substantial evidence demonstrating the existence of an actual emergency and they do not demonstrate any reasoned decision-making.**

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE’s determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 8251. After an objection has been brought before DOE, the Court may consider it with the understanding that “[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.” 16 U.S.C. § 8251. Substantial evidence means “such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.” *Duke Energy Corp. v. FERC*, 892 F.3d 416, 420 (2018). This standard implies deference to an agency’s factual determinations. See, e.g., *id.*

DOE failed to point to substantial evidence of a current and unexpected emergency in the December 23, 2025, to March 23, 2026, timeframe during which the Orders are in effect. The evidence DOE provided does, however, prove that there is currently no energy emergency and that there will not be an “unexpected emergency” that warrants these Orders. MISO is well situated to

³⁰ See, e.g., Integrated Resource Plan, NIPSCO 2024 Summary (Including at page 9, for example, that “NIPSCO will continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2025 retirement of all coal units at Schahfer....”) (accessible at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf).

deliver reliable power throughout its area in the winter, spring, and summer of 2026. Longer-term resource needs are the subject of resource planning, not emergency action.

In declaring the contrary, DOE relied on a 2024 long-term reliability assessment by NERC, (Exs. A-B at 2), but that assessment identified an “elevated” risk for potential capacity exceedance if an extreme weather event were to occur. Ex. J at 6 (defining “elevated risk”). Indeed, the assessment explicitly shows that there will be more than enough anticipated reserve margin every summer through 2031, and every winter through 2032:



Figure 3: MISO Planning Reserve Margin—Summer

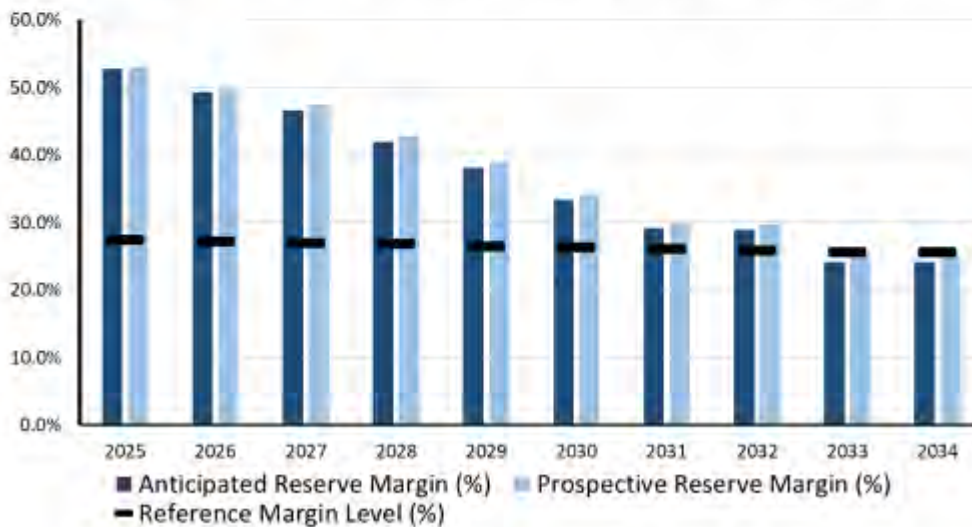


Figure 4: MISO Planning Reserve Margin—Winter

Id. at 13. Thus, the Orders make too much out of too little—the “elevated” category is hardly a call for immediate and unnecessary emergency action when there will be adequate reserve margins for years to come. As the long-term NERC assessment points out, MISO expects to have adequate capacity even factoring in the longstanding plant retirement plans that it approved. Indeed, the

LTRA Executive Summary makes a host of recommendations to ensure system reliability, not one of which is for DOE to issue emergency orders requiring old, unreliable, and expensive coal plants to continue running. Ex. J at 10. While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The “elevated risk” category is not tantamount to an emergency. Even though NERC used the term “elevated risk” for the possibility that there could be an operating reserve shortfall, NERC did not apply the “high risk” category to MISO, and did not call for any retired plants to be brought back online. Moreover, the “elevated risk” designation means that MISO is projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions and is only “at risk of supply shortfall in extreme conditions.” *Id.* at 12. NERC concluded that its probabilistic assessments for MISO “indicate above-normal generator outages during extreme weather can result in unserved energy or load loss.... [w]ith uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.” Thus, there is no emergency. An extreme weather event could cause unserved energy or load loss. But the Orders do not identify any extreme weather event occurring during their timeframe. And even then, the NERC long-term assessment does not say that there would be inadequate methods to address such outages, such as system interconnections.

Perhaps most simply, the “elevated risk” designation is far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated an “elevated” risk in every NERC Summer Reliability Assessment since NERC initiated the

practice of designating regions as “high,” elevated,” or “normal” risk in 2021.³¹ NERC has also designated MISO as “elevated” risk in the 2021-2024 Winter Reliability Assessments since 2021. *Id.* Yet no energy shortage has occurred and DOE has never imposed an emergency declaration until now (see *infra* regarding prejudgment and pretext). And more pertinent here, the latest NERC 2025-2026 Winter Reliability Assessment actually shows MISO as “normal risk” for the winter months—the lowest category of risk designation—as opposed to “elevated risk.”³²

In fact, the evidence before DOE cuts against the Orders. This includes MISO’s PRA for 2025-2026, which found sufficient capacity throughout the region. Exs. K-L. The press release announcing the PRA, (*id.*), confirms “adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026).” Ex. L. And while “the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.” *Id.* The PRA was based on NERC’s standard BAL-502-RF-03 (Ex. M), requiring assessment of “one day in ten year” loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. *Id.* MISO’s PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

³¹ See NERC, *Reliability Assessments*, <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx> (last visited January 20, 2025).

³² North American Electric Reliability Corporation, 2025-2026 Winter Reliability Assessment (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf, at 6 fig. 1.

And beyond the lack of supporting evidence, DOE also acted arbitrarily and capriciously by ignoring well-known and readily-accessible contrary information. For example, DOE failed to consider recent comments by MISO’s Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC’s purported concerns. Ex. N. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised³³) that included capacity shortfalls in 2025, noting that NERC’s assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be “more than adequate,” and that he had “no material concerns” over MISO’s resource adequacy for the upcoming summer. *Id.* Resource sufficiency for the period of the DOE Orders is reinforced by the recent finding of merely “normal risk” in MISO per NERC’s 2025-2026 Winter Reliability Assessment.³⁴ That assessment likewise finds that MISO’s anticipated and projected resources exceed the reference margin level.³⁵

DOE also failed to consider MISO’s history of strong performance through several extreme weather events including Winter Storms Elliot and Uri, and did not credit MISO’s proven track record of engaging in a variety of mechanisms to ensure grid reliability.

³³ NERC, *Statement of NERC’s Long-term Reliability Assessment*, (June 17, 2025) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

³⁴ North American Electric Reliability Corporation, 2025-2026 Winter Reliability Assessment (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf, at 6 fig. 1.

³⁵ *See, id.* at 42 fig. 4. The reference margin level varies by region; it is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads.” *Id.* at 41. MISO’s reference margin level is substantially higher than that of any other region in North America. *See, id.* at 42.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the Orders.

The evidence cited in the Orders does not support the conclusions that DOE draws. For example, the NERC Long Term Reliability Assessment does not identify any war, fuel shortage, or natural disaster. Ex. J. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. *Id.* at 42-44.

A later assessment for the summer of 2025 concluded that all areas were projected to have “adequate anticipated resources for normal summer peak load conditions.” Ex. O. Indeed, the “elevated risk” designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific “dashboard” concludes that MISO’s expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations “could” be necessary for above-normal summer peak load and extreme generator outage conditions:

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

Id. at 16.

Second, the Orders describe a sequence of resource retirements without acknowledging the replacement capacity that came online (or that is/was planned to come online) to offset those

retirements. Exs.A-B. In any event, NERC’s long-term analysis already factored in an assumption that included those retirements. Ex J.

Third, the Orders cite NERC’s “elevated risk” determination. But the retirements of Schahfer and Culley coal operations were already known to, and approved by, MISO operators who accounted for the retirement in their robust resource planning processes (described in further detail herein). Exs. P-Q.

Indeed, the Orders acknowledge that the retirement was already factored into MISO’s own supply forecasts. Exs. A-B at 2. MISO’s PRA (Exs. H, L) confirm adequate margin. *Id.* In fact, for the fall 2025 timeframe, the auction results exceeded MISO’s Reserve Margin Requirement by 2.6%. That means MISO entered the fall with more resources than necessary to ensure grid reliability. Ex. H at 19.

Indeed, for Schahfer, the relevant IRP confirms that NIPSCO would “continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2025 retirement of all coal units.”³⁶

And as the States’ Petitions for Rehearing on the three Campbell Orders explain, the “elevated risk” designation that DOE cites is relatively common and has never presented an emergency before. And nothing in the NERC assessment determined that MISO’s interconnection with other RTOs would be insufficient for additional capacity if needed. Nonetheless, the Orders to the Schahfer and Culley coal units rely on the NERC long-term assessment to claim that “additional dispatch” of the coal plants is “necessary.” Exs. A-B at 2. DOE drew that improper

³⁶ See, e.g., Integrated Resource Plan, NIPSCO 2024 Summary (accessible at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf).

conclusion even though the retiring Schahfer and Culley plants were not included in any of the MISO forecasts finding sufficient capacity.

Fourth, the Orders misstate the conclusions of the PRA by cherry-picking reference to capacity offset while simultaneously acknowledging its conclusion that the results “demonstrated sufficient capacity” for the planning year, which covers 2025-2026. Exs. A-B at 2; contra Ex. H at 12 (“The 2025 PRA demonstrated sufficient capacity”). Sufficient capacity, by definition, is not an emergency.

Fifth, the summer of 2025 is instructive. Even in the peak-demand timeframe of June (Ex. M) and July (Ex. N.), when actual demand reached 120 GW on June 23, MISO had more than enough offered capacity: Ex R at 25, 33; Ex. S at 24, 32. This does not include more than 7000MW in headroom available to MISO beyond the offered capacity shown.³⁷ The Orders do not indicate that the December 23, 2025, through March 23, 2026, timeframe is likely to come anywhere near such demand, or that there would be insufficient capacity to meet it, or that the additional available headroom would not be enough to address any such demand.

Sixth, the Order cites MISO’s attributes roadmap from December 2023. Exs. A-B at 2; Ex. T. But that document is not only relatively old compared to the other information DOE cites, it does not speak to the Winter of 2026. DOE notes that it refers to the potential for risk of loss of load in the summer and fall beginning in 2027. The document does not support the existence of any emergency during the term of the Orders. *Id.* The Orders do not explain how a Section 202(c) order directed to Winter 2026 timeframe will address any emergency in that timeframe—the issue

³⁷ See Public Interest Organization’s Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 70 at ¶¶ 16-19.

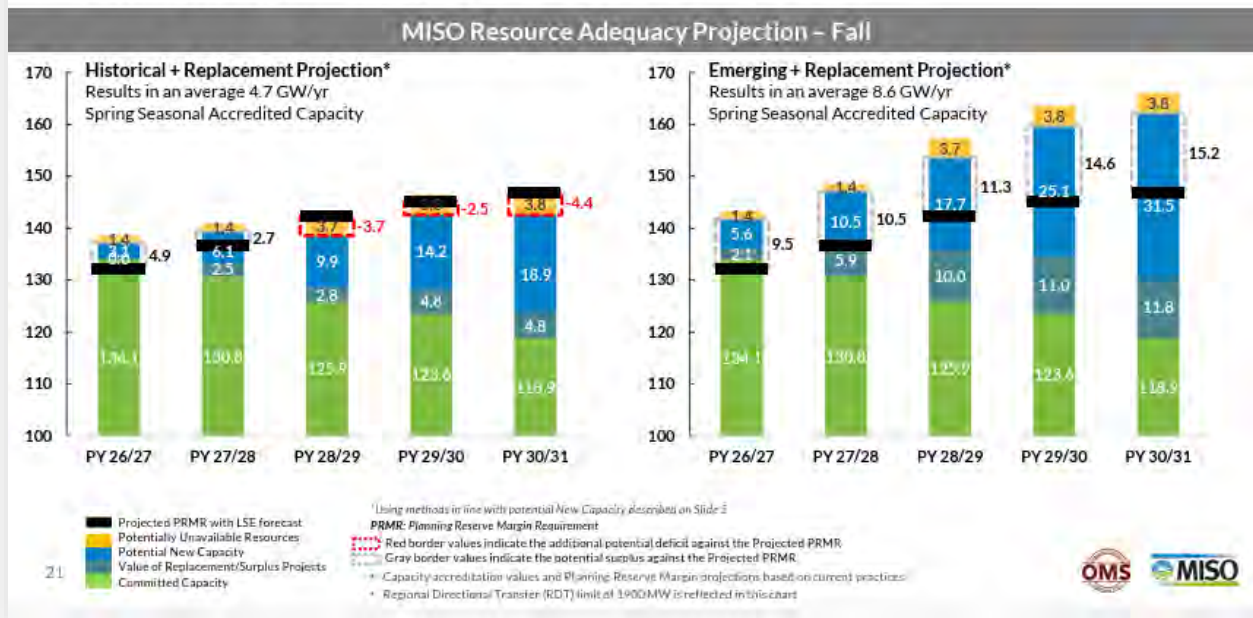
identified is not until 2027 at the earliest. And as discussed above, the most recent NERC winter assessment, applicable during the period of the Orders, does not foresee any such emergency.

Seventh, the Orders cite MISO's Response to the Reliability Imperative, concluding that MISO purportedly has "resource reliability concerns" and quotes a passage acknowledging "risks in non-summer months" that were not historically of concern. Ex. A-B at 2. But the Orders fail to identify how generalized discussion of non-summer "concerns" and potential "risks" demonstrate any particular emergency, much less a specific one that is posed for the Winter 2026 timeframe. To the contrary, the MISO Response to the Reliability Imperative describes the risks posed by non-summer operations in the context of explaining the steps it is taking to address these risks in order to ensure adequate capacity and overall system reliability. Ex. U at 11. It specifically describes four pillars of approaches that MISO intends to deploy, (Ex. U at 12-24), and concludes with a "Roadmap" for how it will deploy its strategy. Ex. U at Appendix A-1. The Orders do not contend that MISO's approach will be adequate, or that there is an emergency despite MISO's robust efforts. *Id.*; *contra* Exs. A-B.

Eighth, the Orders again discuss the 2025-2026 PRA results, which included a statement that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." Ex. A-B at 2-3; *contra* Ex H. Again, the actual document, in its full context, confirms adequate margin for reliability. *Id.*

Ninth, the Orders cite the Organization of MISO states and MISO's joint publication of a survey dated June 6, 2025. Exs. A-B at 3. But that survey confirms a surplus through the summer of 2026, well beyond the scope of the Orders' timeframe. In fact, the survey shows a fall 2026 surplus using seasonally-accredited capacity against the planning reserve margin requirement:

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate



Ex. V at 21. The Orders rely on the survey results to identify potential forecast deficits (which are not emergencies) in the 2027-2030 timeframe—but that is well outside the Winter 2026 timeframe in which the Orders will be in effect, and fails to account for the “Emerging + Replacement Projection” metrics throughout the document showing surpluses against the projected Planning Reserve Margin Requirement. *Id.* at 7, 9, 19-26.

Tenth, Orders further cite Executive Orders directed to building out energy capacity and supporting artificial intelligence. But the Orders do not discuss how these Executive Orders demonstrate any inadequate approach to meeting the projected needs on MISO’s system, much less one that presents an emergency of any sort.

In total, none of this evidence demonstrates that there is any emergency, much less one that might occur in the December 23, 2025, to March 23, 2026, timeframe. To be sure, there are normal capacity considerations including some that pose some degree of potential risk, but not one of the

sources cited in the Orders evidence any lack of adequate planning to address those risks, much less any likelihood of a shortfall between August 20 and November 19, 2025.

Instead, the robust and comprehensive planning processes undertaken by the prime authorities—the individual states, the utilities, and MISO—have comprehensively planned for resource adequacy and system reliability during the period of the Orders and beyond.

Given all of these countervailing considerations, and the full context of the sources that DOE purports to cite, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. The Orders compelling the Schahfer and Culley coal units to operate is arbitrary and capricious.

The States have already documented all of these flaws in three separate requests for rehearing on DOE's equally flawed orders compelling the J.H. Campbell plant to operate (DOE Orders 202-25-3, 202-25-7, and 202-25-9). These requests are hereby incorporated and adopted herein, including their discussion of materials not cited in the Orders subject to this request. These include the comments of Jennifer Curran and the MISO independent market monitor which DOE previously relied upon but has now dropped. The States' prior submissions put DOE on notice of the flawed analysis of its prior orders. Exs. W-X.

Rather than identifying and responding to an actual emergency, both the Orders demonstrate that DOE instead started with a desired result (keeping a coal-fired plant online), and worked backwards to justify that outcome.

B. The Orders exceed DOE's authority because they are not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

DOE exceeds its authority because the Orders do not address any actual emergency or sudden occurrence needing imminent response, and because they have not identified any actual

and specific insufficient supply situation in the Winter 2026 timeframe. Thus the Orders are without authority and contrary to law.

As the statutes make clear, an actual “emergency” is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c). And Department regulations define “emergency” to mean an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission, or distribution of electric power. “Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected ‘entity’ to prevent.” 10 C.F.R. § 205.371. Further, emergency orders must meet “a specific inadequate power supply situation,” and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply “so that a continuing emergency order is not needed.” *Id.*

These requirements have been demonstrated by DOE’s historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1

& 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.³⁸

Past practice further confirms the impropriety of these Orders. While DOE’s emergency powers have occasionally been used to address retirements, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lightning strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

The plain text, prior regulatory interpretation, judicial precedent, and longstanding practice all confirm a limited power applicable only to sudden, imminent conditions. Context makes that all the more plain. *See Food & Drug Admin. v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000) (The “words of a statute must be read in their context and with a view to their place in the overall statutory scheme.”).

A memorandum by the Congressional Research Service, Ex. Y, confirms that DOE’s use of Section 202(c) to order coal plants to remain generally available is wholly novel. Ex. S at 3 (Department engaging in “seemingly new interpretations of the emergency authority”). That novelty violates well-settled law prohibiting agencies from asserting novel, transformational, and impactful authorities that congress did not intend.

³⁸ MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) (“*Winter Storm Elliott Overview*”) at 7, <https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf>.

The Orders impose a transformative and illegal use of section 202(c): as a means to intervene in the regulatory landscape, displacing both state law and sections 205 and 206 of the FPA, under which FERC regulates regional grid operators' resource adequacy requirements. Had Congress intended to vest such a broad power in section 202(c) it would have stated so clearly. Indeed, it defies logic that Congress would grant DOE general authority over which power plants may retire across the country—a function with profound implications for rates, state sovereignty, and a broad array of stakeholder interests—without any obligation to assess the effect on ratepayers or seek public input.

The Supreme Court has emphatically rejected statutory interpretations whereby an agency “claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority.” *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724-25 (2022) (internal quotations omitted); *cf. Whitman v. Am. Trucking Associations*, 531 U.S. 457, 468 (2001) (“Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions . . .”). Yet what DOE issued here is exactly that “extraordinary case[],” *W. Virginia*, 597 U.S. at 721 (cleaned up): the discovery—in a 90-year-old statutory provision used seldomly and only for limited purposes—of unheralded yet broad authority to transform the regulatory environment underpinning the electricity system by commanding the amount and type of generation on the grid. All without “clear congressional authorization,” *id.* at 724, and notwithstanding that such authority has been reserved to and exercised by the States and, at their election, RTOs, for decades. *Cf. Biden v. Nebraska*, 600 U.S. 477, 501 (2023) (“The question here is not whether something should be done; it is who has the

authority to do it”); *W. Virginia*, 597 U.S. at 744 (Gorsuch, J., concurring) (agency overreach “also risks intruding on powers reserved to the States”).

Indeed the statutory structure of the federal power act confirms the short-term nature of emergency approaches. That is because long-term planning authority appears in an entirely different Section of the Federal Power Act – Section 215—which indicates that the emergency authority of Section 202(c) is a different authority altogether. 16 U.S.C. § 824o. Given all of the procedures attendant to resource planning, this statutory structure confirms that emergency orders are not the proper mechanism to engage in resource planning five years into the future. *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); *see also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (DOE’s authority in one Section of the Federal Power Act “is strong evidence” that a separate Section does not confer the same authority on the agency).

Courts have also recognized Section 202(c)’s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply.” 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm’n.*, the Eighth Circuit noted that 202(c) provides authority to “react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency.” 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually

occurring, concluding that a separate provision, section 202(b)³⁹ applies to the former, while section 202(c) applies to the latter:

On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

Otter Tail Power Co., 429 F.2d at 234. In that case, a power company challenged the FPC’s order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was “dangerously close to eroding its firm power supply” due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it “just the type of situation to fit into a § 202(b) hearing rather than § 202(c).” *Id.* The caselaw is therefore clear—emergency orders cannot be used to address longer-term potential future risks that are properly addressed through ordinary planning approaches.

³⁹ Section 202(b) refers to 16 U.S.C. § 824a(b), which states “[w]henver the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility” if the utility would not face an undue burden. The DOE’s authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

Statutory text and structure, past practice, and caselaw are therefore all clear: for DOE to have any authority under section 202(c), the emergency must be actual and not merely a broadly asserted future risk. With no such actual or imminent emergency, the Orders are unlawful.

C. The Orders exceed DOE’s authority because they requires actions not listed in Section 202(c)(1).

The Orders are unlawful because they purport to require actions not within DOE’s statutory authority.

DOE’s authority is limited to issuing orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant availability untethered to meeting any specific need, nor does it allow for potential economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur, and specifically does not allow for the Department to order availability without a specific need to be available.⁴⁰ Plus, “economic dispatch” is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO’s determination of lowest-cost sources may not result in the Schahfer or Culley coal units producing *any* generation whatsoever during the Winter 2026

⁴⁰ Before these two Orders and the three Campbell orders, DOE had issued Section 202(c) emergency orders only 19 times in history. Only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

timeframe. (Or if it does, it could be as a result of the Orders rather than an external need.) Thus, the Orders are without authority and contrary to law.

D. The Orders exceed DOE’s authority because they do not set hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

Any emergency order issued under Section 202(c) must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

But the Orders at issue here address only the potential for an emergency, they do not identify a need for the Schahfer or Culley coal units to generate electricity to meet it. By the same token, the Orders do not establish any limited hours or other parameters for the Schahfer or Culley coal units to follow to ensure their usage is what actually meets the purported emergency, only that they be available at all times. Thus the Orders are without authority and contrary to law, and allow the Schahfer and Culley coal units to generate electricity during times there are not even “elevated risks.” Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the environmental impacts that, by law, the Orders must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus the Orders are without authority and contrary to law.

E. The Orders exceed DOE’s authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends “only to those matters which are not subject to regulation by the States.” 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired is traditionally subject to state regulation. States retain jurisdiction “over facilities used for the generation of electric energy.” 16 U.S.C. § 824(b)(1). “The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy” *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir.

2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that the Federal Energy Regulatory Commission may consult with states “regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.”) 16 U.S. Code § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force. Ex. T. And more recently, a Federal-State Current Issues Collaborative. Ex. U.

Section 103 of the Department of Energy Organization Act, also applicable, mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Public Utilities Commission⁴¹ in Minnesota, the Wisconsin Public Service Commission, and the Indiana Utility Regulatory Commission (IURC).⁴² These bodies oversee the development of Integrated Resource Plans (“IRPs”), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota’s IRP statute). An IRP can

⁴¹ Minnesota Public Utilities Commission, *Utility Planning*, <https://mn.gov/puc/activities/economic-analysis/planning/> (last visited June 23, 2025).

⁴² Wis. Stat. Ann. § 196.491 (West).

consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.⁴³ Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.⁴⁴ As discussed above, the planned retirements of the Schahfer and Culley units at issue were subject to such a process before the IURC.⁴⁵

MISO, in turn, is one of the country’s largest regional transmission organizations (RTOs), which were formed to develop transmission systems, trading markets, and attendant procedures.⁴⁶ MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.⁴⁷ This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.⁴⁸ MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And

⁴³ *Id.*

⁴⁴ Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, <https://mn.gov/puc/activities/economic-analysis/planning/irp/> (last visited June 23, 2025).

⁴⁵ *See, e.g.*, Complaint and Request for Fast Track Processing of Northern Indiana Public Service Company LLC, FERC Docket EL26-36-000 at 7 (December 29, 2025) (“NIPSCO’s 2021 Integrated Resource Plan (“IRP”) included a retirement analysis to assess retirement dates for different generating units of its existing generation fleet”); *See also, e.g.*, Complaint Requesting Fast Track Processing, FERC Docket EL26-38-000 at 9 – 10 (January 5, 2026).

⁴⁶ FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

⁴⁷ MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).

⁴⁸ *Id.*

MISO then accounts for the final IRPs in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.⁴⁹ MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual PRA, which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.⁵⁰

The Schahfer and Culley coal units' planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including Indiana's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether the retirement will pose any concern for grid reliability.⁵¹

Both CenterPoint and NIPSCO submitted relevant Attachment Y forms to provide notice that they planned to suspend generation at these plants. MISO approved of such retirements. Ex.

⁴⁹ *Id.*

⁵⁰ MISO, *Resource Adequacy*, <https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc> (last visited June 23, 2025).

⁵¹ If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

E. In making its approval, MISO determined that such retirements “would not result in violations of applicable reliability criteria.” Ex. E at 9.

DOE did not adequately consult with the States, much less account for or incorporate the findings of MISO when it approved these Attachment Y submissions. The Orders are wholly silent as to any consultation with the State of Indiana in which all three coal units are located. Yet State regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in their states. *Zibelman*, 906 F.3d at 50. DOE’s failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of Federal Power Act regarding federal-state collaboration and upends FERC’s historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely “practicable” here given the lack of an imminent emergency. The Orders did not give any consideration (much less due consideration) to Indiana’s IRP in violation of law. 42 U.S.C. § 7113.

In the Orders’ focus on longer-term risks, including the growth of data centers and the projections out into the 2027-2030 timeframe, DOE is improperly inserting itself into long-term resource planning, usurping a role belonging to the respective states and MISO. The DOE cannot use short-term emergency orders to serve a purpose for which DOE’s emergency authority was not designed: to supplant the states’ primary authority in the long-term resource planning arena, or to reject the carefully considered work that MISO puts into planning resources.

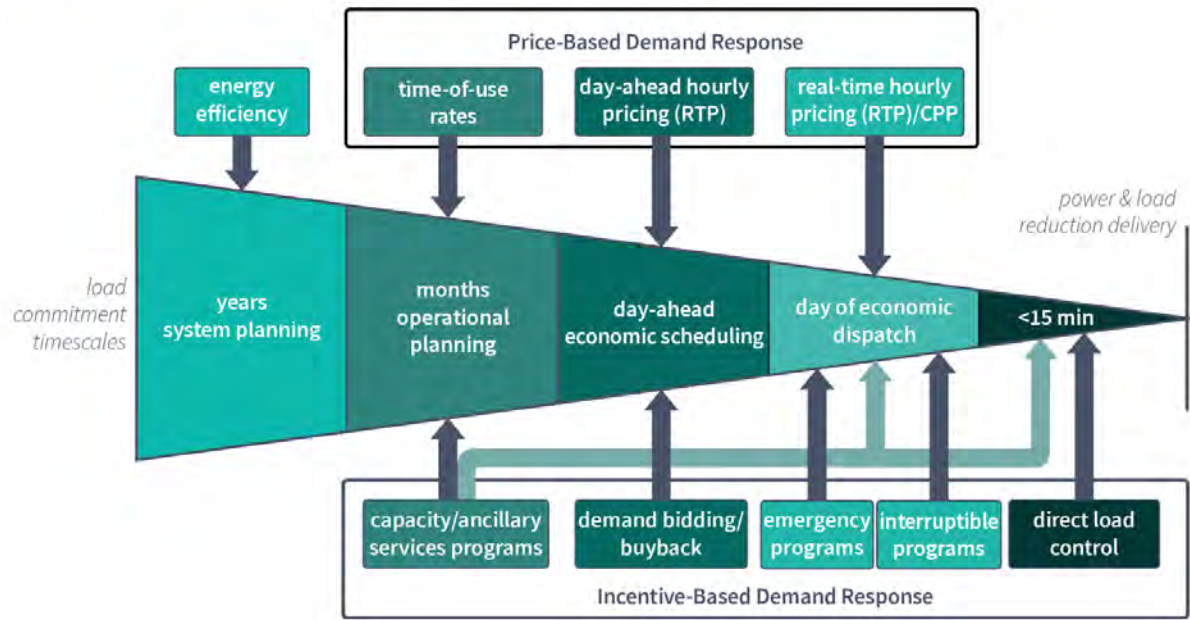
The Orders usurp the States’ and MISO’s primary rule in resource planning and development; it is contrary to law.

F. The Orders are unreasoned, arbitrary, and capricious because their directive for “economic dispatch” is inherently contradictory with the needs to meet an actual emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must “best meet the emergency and serve the public interest.” 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an order, these two Orders are not rationally related to address the emergency that the Orders identify.

The Orders’ specific requirement for MISO to take steps to effectuate “economic dispatch” of the Schahfer and Culley coal units undermines their determination that an emergency exists and cannot “best meet” the purported emergency. Economic dispatch is a term of art for the procedure by which MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. “Economic dispatch,” by definition, is awarded to the lowest-cost option (all else being equal). Ex. Z. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy⁸²

Ex. Z at 43. Most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Ex. AA at 6-7, 13, 51. As recently as 2021, the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal. See Ex. BB at 2.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

The Orders’ proposed solution for “economic dispatch” of the Schahfer and Culley coal units is thus inherently incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, even uneconomic plants receive cost-of-

service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a “price taker” using MISO’s “must run” classification. Thus, the Orders’ directive to use “economic dispatch” is irrational: actual emergencies are not addressed with economic dispatch, and economic dispatch is a necessarily ineffective method to address an actual emergency.⁵²

Moreover, the Orders’ requirement that the Schahfer and Culley coal units be “available to operate” does not accord with 202(c)(1)’s requirement that DOE select the temporary measure that will “best meet the emergency and serve the public interest.” Section 202(c)(1)’s use of the term “best” shows that the Commission cannot require temporary power generation from the Schahfer and Culley coal units when better means are available to meet the alleged emergency and serve the public interest. *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (“Best” means what is “most advantageous.” (Quoting Webster’s New International Dictionary 258 (2d ed.1953))). DOE’s decision to require the plants to be available disregarded its obligation to consider alternatives and select the best one.

Although DOE need not consider every conceivable alternative, it must consider those that are obvious and viable. *See Dep’t of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass’n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat’l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013).

⁵² Campbell’s situation illustrates this inefficiency. Coal is an expensive fuel type in our current energy mix. The inefficiency of running a coal plant makes it uneconomic in general, which is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g., Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order). Indeed, DOE's regulations specify information it shall consider when deciding to issue an order under section 202(c). 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id.* § 205.373(g)–(h); Ex. CC at 4 (DOE Order No. 202-22-4). DOE has not explained why ordering the Schahfer and Culley coal units to remain "available" meets any of these criteria, especially in light of alternatives such as power pooling and utility coordination.

Even if there were an emergency, DOE has not explained why its Orders "best" meets the emergency. That is because they do not. Again, the Orders allege only that the Schahfer and Culley coal units should remain available because a need for additional capacity *might* arise in the future (and even then, most likely years from now, not in the Winter 2026 timeframe). Given the speculative nature of the alleged emergency, it is incorrect as a matter of fact that ordering the Schahfer and Culley coal units to remain available is the best means of addressing it. DOE's failure to consider alternatives other than the inefficient and incapable Schahfer and Culley coal units does not meet section 202(c) requirement for DOE to use its judgment to choose the best temporary source of emergency energy.

First, if an emergency need occurs in the day-of or real-time markets, the Schahfer and Culley coal units will not be able to spool up in time to meet that need. That is because it takes hours or days for coal plants like Schahfer and Culley coal units to reach peak load.⁵³

Second, even if there were adequate notice for the Schahfer and Culley coal units to deliver energy in an emergency, their age and unreliability make them a poor choice to rely on for emergency services.⁵⁴ Their age and need for repair/maintenance were key among the reasons they were slated for retirement.

Third, even if there were adequate transmission and lead time, the Schahfer and Culley coal units use an expensive fuel source, which means that their bid to provide electricity would be higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), which would prevent it from being selected as the most economic resource to meet the need. The Schahfer units are together responsible for a maximum of 847MW of nameplate generation (when they are operational and capable of achieving peak load).⁵⁵ Schahfer Unit 18 is not even available to run during the timeframe of the Orders; and Culley Unit 2 is responsible for only 100 MW. *Id.* That represents a small fraction of the remaining margin that MISO had available in the summer of 2025 and demonstrates that these coal plants are not an efficient means of meeting an emergency energy demand.

⁵³ See Forms EIA-860 and EIA923, available at <https://www.eia.gov/electricity/data/eia860/>; <https://www.eia.gov/electricity/data/eia923/>.

⁵⁴ See Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibits 103-104.

⁵⁵ Sourced from <https://campd.epa.gov/data/custom-data-download>

Finally, if, for example, there were a need for additional electricity in North Dakota in March of 2026, it is unlikely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Schahfer and Culley coal units to meet that need.

Rather than order the Schahfer and Culley coal units to remain available, DOE was required to consider obvious alternatives that MISO has available and uses as part of its role as a regional transmission grid operator. The Department has long recognized that power pools and utility coordination “are a basic element in resolving electric energy shortages.” *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports.⁵⁶ The fact that DOE has intruded on MISO’s role of planning for and meeting fluctuations in demand without considering these viable and obvious alternatives shows that it did not comply with section 202(c).

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Orders improperly impose measures that are not tailored to anything. All the while, the Orders impose costs on the States to bring the Schahfer and Culley coal units to operational status beyond their planned retirements, add potentially expensive generation to the mix if the Schahfer and Culley coal units were to run in the Winter 2026 timeframe, and generate harmful pollution at the

⁵⁶ See, e.g., Public Interest Organization’s Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 43 at § III.A.3.b (Winter Storm Elliott System Operations Inquiry) (“Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day.”); Exhibit 44 at 43 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA and other neighboring regions), 83–84 (describing PJM power exports to MISO and graphically depicting those exports over time); Exhibit 36 at 6 (MISO Elliott Max. Gen. Event Overview) (“MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW.”); and Exhibit 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

same time. Thus, the Orders requiring the Schahfer and Culley coal units to remain available and for MISO to take steps to use the Schahfer and Culley coal units for economic dispatch is irrational and arbitrary where the Schahfer and Culley coal units are unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need they is supposed to meet in the first place.

Therefore, the Orders are not rationally related to meeting the need of the purported emergency that they identify.

G. The purported emergency is pretext for a prejudged outcome.

The two Orders are not a good faith effort to carry out DOE’s duties under the Federal Power Act. Rather, the materials supporting the Orders demonstrate a pretextual effort to further the administration’s policy support for fossil fuels, and in particular coal electricity generation.

Where the conduct of the agency shows an “unalterably closed mind on matters critical to the disposition of th[is] proceeding,” it requires either disqualification of the administrator or withdrawal of the proposal. *Ass’n of Nat’l Advertisers v. FTC*, 627 F.2d 1151, 1170 (D.C. Cir. 1979); *Nehemiah Corp. of Am. v. Jackson*, 546 F.Supp. 2d 830, 847 (E.D. Cal. 2008) (describing the appropriate remedies when an agency official has prejudged the outcome of a particular matter). A preexisting internal directive to reach a particular result is strong evidence that the official is not “free, both in theory and in reality, to change his mind” in the agency proceedings. *Nat’l Advertisers*, 627 F.2d at 1172; see *Int’l Snowmobile Mfrs. Ass’n v. Norton*, 340 F. Supp. 2d 1249, 1260 (D. Wyo. 2004).

The Orders cite to a bevy of Executive Orders declaring an energy emergency. Even if these Executive Orders are taken at face value, they are incoherent with the President’s other actions to reduce capacity of new energy generation, such as from ongoing and nearly-completed

wind projects. *Temporary Withdrawal of All Areas on the Outer Continental Shelf From Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects* 90 Fed. Reg. 8,363 (Jan. 20, 2025); *Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources*, 90 Fed. Reg. 30,821 (Jul. 10, 2025).

Further, the administration has declared a preference for coal energy. *Executive Order 14261: Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15,517 (Apr. 8, 2025). The express mandate of Executive Order 14261 declared it to be the national policy “to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production, encouraging the utilization of coal to meet growing domestic energy demands, increasing American coal exports, and ensuring that Federal policy does not discriminate against coal production or coal-fired electricity generation.”

But this was not a simple policy preference—the administration had already predetermined that it would resort to emergency authority to reopen or forestall closure of coal plants before it ever issued these Orders. On April 8, 2025, President Trump gave remarks during the signing ceremony for Executive Order 14261. In those remarks, he noted that the administration would take action to reopen coal plants.⁵⁷ Also on April 8, 2025, the Department of Energy announced several initiatives directed to increasing coal production.⁵⁸

⁵⁷ <https://www.presidency.ucsb.edu/documents/remarks-domestic-coal-production> (“And all those plants that have been closed are going to be opened if they're modern enough.” And “From now on, we'll ensure that our Nation's critically needed coal plants, as an example, remain online and fully operational. They're always going to be operational.”)

⁵⁸ <https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing>

During a Bloomberg TV interview in February 2025, Secretary Wright declared that the United States should stop the closure of coal power plants, and asserted that DOE had the authority to do so.⁵⁹

On July 7, 2025, Secretary Wright was quoted as saying, “I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those.”⁶⁰

On July 11, 2025, the DOE posted a video Secretary Wright to the department’s social media accounts with the chyron, “BIG BEAUTIFUL CLEAN COAL. This is the largest source of global electricity and third largest source of electricity in the U.S.”⁶¹

The DOE’s social media feeds are full of clips from Secretary Wright media appearances extoling coal plants, promising to increase the use of coal for energy production, and asserting that DOE had the authority to forestall closures.

The administration, and DOE in particular, engaged in prejudgment of the Orders. Knowing that it needed to effectuate the administration’s policy preference to keep coal plants open, DOE worked backwards from that preferred result and justified it using post-hoc rationalizations. Secretary Wright demonstrated an “unalterably closed mind on matters critical to the disposition” of the use of emergency authority, requiring the Orders to be set aside. *Nat’l Advertisers*, 627 F.2d at 1170; *Nehemiah Corp.*, 546 F.Supp. 2d at 847.

⁵⁹ <https://www.bloomberg.com/news/articles/2025-02-11/us-should-stop-closure-of-coal-fired-power-plants-wright-says>.

⁶⁰ https://www.wvnews.com/statejournal/news/top_story/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_4ffcdad0-9030-4e6f-8ca7-0816e1786cbc.html

⁶¹ *E.g.*, <https://www.facebook.com/energy/videos/big-beautiful-clean-coal-this-is-the-largest-source-of-global-electricity-and-th/1468968367585884/>.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Orders directing Schahfer and Culley coal units to operate.

**KEITH ELLISON
ATTORNEY GENERAL
OF MINNESOTA**

/s/ Peter Surdo

Peter Surdo
Cat Rios-Keating
Alyssa Bixby-Lawson
Special Assistant Attorneys General
Office of the Minnesota Attorney General
445 Minnesota St., Suite 600
St. Paul, MN 55101

Dated: January 22, 2026

**DANA NESSEL
MICHIGAN ATTORNEY GENERAL**

/s/ Lucas Wollenzien

LUCAS WOLLENZIEN (P86928)
MICHAEL E. MOODY (P51985)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Dated: January 22, 2026

**KWAME RAOUL
ATTORNEY GENERAL OF
THE STATE OF ILLINOIS**

/s/ Samuel C. Lukens

Jason James, Special Assistant Attorney
General
Office of the Illinois Attorney General
115 South LaSalle, 25th Floor
Chicago, Illinois 60603

Dated: January 22, 2026

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2025

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____
Commission file number 001-16189

NiSource Inc.

(Exact name of registrant as specified in its charter)

DE

(State or other jurisdiction of
incorporation or organization)

801 East 86th Avenue
Merrillville, IN

(Address of principal executive offices)

35-2108964

(I.R.S. Employer
Identification No.)

46410

(Zip Code)

(614) 460-6000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class

**Trading
Symbol(s)**
NI

**Name of Each Exchange on Which
Registered**
NYSE

Common Stock, par value \$0.01 per share

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large accelerated filer Accelerated Filer Emerging Growth Company Non-accelerated Filer Smaller Reporting Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrants included in the filing reflect the correction of an error to previously issued financial statements.

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of the registrant's common stock, par value \$0.01 per share (the "Common Stock") held by non-affiliates was approximately \$18,966,136,571 based upon the June 30, 2025, closing price of \$40.34 on the New York Stock Exchange.

There were 478,533,171 shares of Common Stock outstanding as of February 4, 2026.

Documents Incorporated by Reference

Part III of this report incorporates by reference specific portions of the Registrant's Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 11, 2026.

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DEFINED TERMS

The following is a list of frequently used abbreviations or acronyms that are found in this report:

NiSource Subsidiaries and Affiliates (not exhaustive)

Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
GenCo	NIPSCO Generation LLC
Generation Holdings I	Generation Holdings I LLC
Generation Holdings II	Generation Holdings II LLC
NIPSCO	Northern Indiana Public Service Company LLC
NIPSCO Holdings I	NIPSCO Holdings I LLC
NIPSCO Holdings II	NIPSCO Holdings II LLC
NiSource ("we," "us" or "our")	NiSource Inc.
Rosewater	Rosewater Wind Generation LLC and its wholly owned subsidiary, Rosewater Wind Farm LLC
Indiana Crossroads Solar	Indiana Crossroads Solar Generation LLC and its wholly owned subsidiary, Meadow Lake Solar Park LLC
Indiana Crossroads Wind	Indiana Crossroads Wind Generation LLC and its wholly owned subsidiary, Indiana Crossroads Wind Farm LLC
Dunn's Bridge I	Dunn's Bridge I Solar Generation LLC and its wholly owned subsidiary, Dunns Bridge Solar Center, LLC
Gibson	Gibson Solar LLC
Fairbanks	Fairbanks Solar Energy Center LLC

Abbreviations and Other

AFUDC	Allowance for funds used during construction
ADS	Amazon Data Services, Inc.
ADS Contract	NIPSCO agreement to provide electricity to ADS' data centers
Amended LLC Agreement	Third Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II
AOCI	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
BIP	BIP Blue Buyer L.L.C.
BIP Blue Buyer VCOC L.L.C.	BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company and also an affiliate of Blackstone
BIP Orion Holdco L.P.	BIP Orion Holdco L.P., a Delaware limited liability company and also an affiliate of Blackstone
BIP Orion Holdco II L.P.	BIP Orion Holdco II L.P., a Delaware limited liability company and also an affiliate of Blackstone
Blackstone	Blackstone Infrastructure Partners L.P.
Blackstone Investor	BIP Orion Holdco L.P. and BIP Orion Holdco II L.P. affiliates of Blackstone (GenCo Minority Interest Transaction) and Blackstone Infrastructure Partners, affiliates of Blackstone (NIPSCO Minority Interest Transaction)
BTA	Build-transfer agreement
Cavalry	Cavalry Solar Generation Center

	<u>DEFINED TERMS</u>
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEO	Chief Executive Officer
CEP	Ohio Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
CFO	Chief Financial Officer
CISA	Certified Information Systems Auditor
CISO	Chief Information Security Officer
CISSP	Certified Information Systems Security Professional
CODM	Chief Operating Decision Maker
Columbia Operations	Reportable segment comprised of the results of NiSource Gas Distribution company, including all of its Columbia Gas distribution companies and related subsidiaries
Contract Assets	Generation assets and related transmission infrastructure to be developed in connection with the ADS Contract
Corporate Units	Series A Corporate Units
CPCN	Certificate of Public Convenience and Necessity
CRISC	Certified in Risk and Information Systems Control
C&HC Committee	Compensation and Human Capital Committee
DSIC	Distribution System Improvement Charge
DSM	Demand Side Management
Dunn's Bridge II	Dunn's Bridge II Solar Generation
EPA	United States Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPC Contracts	Engineering, procurement, and construction contracts
EPS	Earnings per share
Equity Units	Series A Equity Units
ERP	Enterprise Resource Planning
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GCT	Generation Cost Tracker
GenCo Minority Interest Transaction	A transaction between NiSource, Generation Holdings II (sole owner of GenCo) and Blackstone Investor pursuant to a purchase and sale agreement entered into in October 2025, that offered equity interests in Generation Holdings II in exchange for capital contributions by the parties.
Generation Holdings II LLC Agreement	Amended and Restated Limited Liability Company Agreement of Generation Holdings II
Generation Assets	Power generations facilities and battery storage to be developed in connection with the ADS Contract
GHG	Greenhouse gases
GWh	Gigawatt hours
HLBV	Hypothetical Liquidation at Book Value
IRA	Inflation Reduction Act

	<u>DEFINED TERMS</u>
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
JV	Joint Venture
LDCs	Local distribution companies
LIFO	Last-in, first-out
LIHEAP	Low Income Heating Energy Assistance Programs
Massachusetts Business	All of the assets sold to, and liabilities assumed by, Eversource Energy pursuant to the applicable asset purchase agreement
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NIPSCO Electric	The electric generation and transmission activities of the NIPSCO Operations reportable segment
NIPSCO Gas	The gas distribution activities of the NIPSCO Operations reportable segment
NIPSCO Holdings II LLC Agreement	Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II
NIPSCO Minority Interest Transaction	A transaction between NiSource, NIPSCO Holdings II (sole owner of NIPSCO) and an affiliate of Blackstone pursuant to a purchase and sale agreement entered into on June 17, 2023, that offered equity interests in NIPSCO Holdings II in exchange for capital contributions by the parties.
NIPSCO Operations	Reportable segment comprised of the results of NIPSCO Holdings I, NIPSCO Holdings II, and NIPSCO and all related subsidiaries
NYMEX	The New York Mercantile Exchange
OPEB	Other Postemployment Benefits
PCB	Polychlorinated biphenyls
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power Purchase Agreement
PUCO	Public Utilities Commission of Ohio
ROE	Return on Equity
RNG	Renewable Natural Gas
ROU	Right of Use
SAVE	Steps to Advance Virginia's Energy Plan
Scope 1 GHG Emissions	Direct emissions from sources owned or controlled by us (e.g., emissions from our combustion of fuel, vehicles, and process emissions and fugitive emissions)
Scope 2 GHG Emissions	Indirect emissions from sources owned or controlled by us
SEC	Securities and Exchange Commission
SMRP	Safety Modification and Replacement Program
SMS	Safety Management System
STRIDE	Strategic Infrastructure Development and Enhancement
TCJA	An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018 (commonly known as the Tax Cuts and Jobs Act of 2017)

DEFINED TERMS

TDSIC	Transmission, Distribution and Storage System Improvement Charge
TSA	Transportation Security Administration
Templeton	Templeton Wind Energy Center
VIE	Variable Interest Entity
WAM	Work and Asset Management enterprise resourcing system

Note regarding forward-looking statements

This Annual Report on Form 10-K contains "forward-looking statements," within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, planned expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are not statements of historical fact. Expressions of future goals and expectations and similar expressions reflecting something other than historical fact, including "may," "will," "should," "could," "would," "aims," "seeks," "expects," "plans," "anticipates," "intends," "believes," "estimates," "predicts," "potential," "targets," "forecast," and "continue," are intended to identify forward-looking statements. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially. Investors and prospective investors should understand that many factors impact whether any forward-looking statement contained herein will, or can be, realized. Any one of those factors could cause actual results to differ materially from those projected.

Factors that could cause actual results to differ materially from those projected in any forward-looking statement discussed in this Annual Report on Form 10-K include, among other things:

- our ability to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities;
- our ability to manage data center growth in our service territories;
- potential incidents and other operating risks associated with our business;
- our ability to work successfully with our JV partners;
- our ability to construct, develop and place into service the Contract Assets and any other generation or transmission assets we develop to support future data center contracts on time or at all and consistent with initial cost estimates, as well as the performance of such assets once constructed and placed into service;
- our ability to obtain the significant additional financing required to construct the Contract Assets and any other generation or transmission assets we develop to support future data center contracts on favorable terms, if at all;
- our ability to recover our investments and realize our expected return under the ADS Contract and any future data center contracts that we enter into;
- our ability to maintain our investment grade credit ratings as we finance and pursue our data center strategy, including our performance under the ADS Contract and any future data center contracts that we enter into;
- ADS' performance under the ADS Contract and the performance of our customers under any future data center contracts;
- any decision by ADS to terminate or reduce the committed capacity under the ADS Contract or any decision by any customer under any future data center contract to terminate or reduce the committed capacity under the contract;
- potential changes in the MISO accreditation treatment of capacity resources;
- our ability to adapt to, and manage costs related to, advances in technology, including alternative energy sources and changes in related laws and regulations;
- our increased dependency on technology;
- impacts related to our aging infrastructure;
- our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses;
- the success of our electric generation strategy;
- construction risks and supply risks;
- fluctuations in demand from residential and commercial customers;
- fluctuations in the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demand;
- our ability to attract, retain or re-skill a qualified, workforce and maintain good labor relations;
- our ability to manage new initiatives and organizational changes;

- the performance and quality of third-party suppliers and service providers;
- our ability to manage the financial and operational risks related to achieving our carbon emission reduction goals, including our Net Zero Goal (as defined below), including any future associated impact from business opportunities such as data center development as those opportunities evolve;
- regulation and the impact of regulatory rate reviews;
- our ability to obtain expected financial or regulatory outcomes;
- potential cybersecurity attacks or security breaches;
- increased requirements and costs related to cybersecurity;
- any damage to our reputation;
- the impacts of natural disasters, potential terrorist attacks or other catastrophic events;
- the physical impacts of climate change and the transition to a lower carbon future;
- our debt obligations;
- any changes to our credit ratings or the credit ratings of certain of our subsidiaries;
- adverse economic and capital market conditions, including increases in inflation or interest rates, recession, or changes in investor sentiment;
- the actions of activist stockholders;
- economic conditions in certain industries;
- the ability of customers and suppliers to fulfill their payment and contractual obligations;
- the ability of our subsidiaries to generate cash;
- pension funding obligations;
- potential impairments of goodwill;
- the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation;
- compliance with changes in, or new interpretations of applicable laws, regulations and tariffs;
- the cost of compliance with environmental laws and regulations and the costs of associated liabilities;
- changes in tax laws or the interpretation thereof; and
- other matters set forth in Part I, Item 1, "Business," Part I, Item 1A, "Risk Factors" and Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report, some of which risks are beyond our control.

In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statement to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to expected results over time or otherwise, except as required by law.

NiSOURCE INC.

PART I

ITEM 1. BUSINESS

Business

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.8 million customers in six states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999.

NiSource's principal subsidiaries include NiSource Gas Distribution Group, Inc. (a holding company that owns Columbia of Kentucky, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, and Columbia of Virginia), and NIPSCO Holdings I (a holding company that owns a controlling interest in NIPSCO, a gas and electric utility). NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses. In addition, NiSource will develop the generation resources it plans to use in serving data center customers through its subsidiary Generation Holdings I (a holding company that holds a controlling interest in GenCo).

Business Strategy

Our business strategy focuses on providing safe and reliable service through our core, rate-regulated, asset-based utilities, with the goal of adding value to all of our stakeholders. Our utilities continue to advance our core safety, infrastructure and environmental investment programs, supported by complementary regulatory and customer initiatives across the six states in which we operate. In 2025, we entered into the ADS Contract, a customized agreement under which NIPSCO will provide electric service to ADS by procuring power from GenCo, which will develop related generation assets, and we expect our data center operations to continue to grow.

Our goal is to develop strategies that (i) support long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) drive value and enable growth in an evolving energy ecosystem. These strategies focus on improving safety and reliability, enhancing customer experience, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer affordability and reducing emissions while generating sustainable returns.

We remain committed to the advancement of our SMS for the safety of our customers, communities and employees. Our SMS is the established operating model within NiSource. NiSource continues to maintain its certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our SMS. In 2025, NiSource successfully maintained its ISO 55001 Asset Management certifications through LRQA, a global leader in engineering and technology services. These certifications reaffirm our unwavering commitment to safety for our employees and partners, customers, and systems and highlight our continued dedication to operational excellence and the integrity of our SMS.

NiSource has two reportable segments: Columbia Operations and NIPSCO Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, consist of our centralized corporate activities and are primarily comprised of interest expense on holding company debt and unallocated corporate costs and activities, as well as new business development costs associated with GenCo. The following is a summary of the business for each reporting segment. Refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for additional information related to each segment.

Columbia Operations

Columbia Operations provides natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. We operate approximately 37,300 miles of distribution main pipeline plus the associated individual customer service lines and 310 miles of transmission main pipeline located in our service areas described above. Throughout our service areas we also have gate stations and other operations support facilities. See below for information on our owned storage facilities. There were no significant disruptions to our system or facilities during 2025.

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Facility Name	Location	Type	Storage Capacity (MCF)
Eagle Cove Propane	Petersburg, VA	Propane Gas	863
South Wales Propane	Jeffersonton, VA	Propane Gas	863
Portsmouth Propane-Air	Portsmouth, VA	Propane-Air Gas	17,300
Total Capacity			19,026

Competition. Due to open access and the deregulation of natural gas supplies, our LDC customers can purchase gas directly from producers and marketers in an open, competitive market. Certain of our subsidiaries are involved in programs that provide our residential and commercial customers the opportunity to purchase their natural gas requirements from third parties and use our subsidiaries for transportation services. As of December 31, 2025, 34.9% of our residential customers and 41.1% of our commercial customers participated in such programs.

We compete with (i) investor-owned, municipal, and cooperative electric utilities throughout our service areas, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil. We continue to be a well-positioned competitor in the energy markets in which we operate due to customer preference for natural gas.

Additionally, we are subject to seasonal fluctuations in sales. Revenues from our gas distribution operations are more significant during the heating season, which is from October through May. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - Columbia Operations," for additional information.

NIPSCO Operations

NIPSCO Operations includes the results of NIPSCO Holdings I and its majority-owned subsidiaries, including NIPSCO, which has fully regulated gas and electric operations in northern Indiana.

NIPSCO Gas

NIPSCO Gas distributes natural gas to approximately 0.9 million customers in northern Indiana. We operate approximately 18,100 miles of distribution main pipeline plus the associated individual customer service lines and 720 miles of transmission main pipeline located in our northern Indiana service areas. Throughout northern Indiana, we also have gate stations and other operations support facilities. See below for information on our owned storage facilities. There were no significant disruptions to our system or facilities during 2025.

Facility Name	Location	Type	Storage Capacity (MCF)
Royal Center Underground Storage	Royal Center, IN	Natural Gas	7,240,000
Rolling Prairie LNG	Rolling Prairie, IN	Liquified Natural Gas	4,000,000
Total Capacities			11,240,000

Competition. Similar to the Columbia Operations segment, NIPSCO Gas operates in an open and competitive market which allows retail customers to purchase gas directly from producers and marketers. As of December 31, 2025, 6.8% of our residential customers and 18.5% of our commercial customers participated in such programs.

We compete with (i) investor-owned, municipal, and cooperative electric utilities throughout our northern Indiana service area, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil. We continue to be a well-positioned competitor in the northern Indiana market due to customer preference for natural gas.

Additionally, we are subject to seasonal fluctuations in sales. Revenues from our gas distribution operations are more significant during the heating season, which is from October through May. Please refer to Part II, Item 7, "Management's

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Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - NIPSCO Operations," for additional information.

NIPSCO Electric

We generate, transmit and distribute electricity to approximately 0.5 million customers in 20 counties in the northern part of Indiana. We also engage in wholesale electric and transmission transactions, and enter into customized agreements to provide electric service to data center customers. Our transmission system, has voltages from 69,000 to 765,000 volts, and consists of approximately 3,000 circuit miles. We are interconnected with eight neighboring electric utilities. We operate 65 transmission and 240 distribution substations, and own approximately 312,500 poles. We own and operate generation assets as well as source power through PPAs. We currently have eight renewable generation facilities in service, three of which were placed into service in 2025. As of December 31, 2025, we also have multiple PPAs that provide approximately 1,200 MW of capacity, with contracts expiring between 2038 and 2045. We also operate two hydroelectric generation facilities, a CCGT, and two coal generation facilities.

In December 2025, before the planned retirement of the R.M. Schahfer coal facility, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring R.M. Schahfer to continue operating for 90 days, through March 23, 2026. The order stated that continued operation of R.M. Schahfer was required to meet an energy emergency across MISO's North and Central regions and authorizes NIPSCO to obtain cost recovery pursuant to 16 U.S.C. § 824a(c). For additional information, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - "Results and Discussion of Operations - NIPSCO Operations," and Part I, Item 1A. "Risk Factors." The Michigan City coal facility is scheduled to be retired by the end of 2028.

We had forced outages during 2025, none of which had material impacts to our operations. See below for information on our owned generating facilities:

Facility Name	Location	Fuel Type	Generating Capacity (MW) ⁽¹⁾
R.M. Schahfer	Wheatfield, IN	Steam - Coal	722
Michigan City	Michigan City, IN	Steam - Coal	455
Sugar Creek	West Terre Haute, IN	CCGT	665
R.M. Schahfer	Wheatfield, IN	Natural Gas	155
Oakdale	Carroll County, IN	Hydro	9
Norway	White County, IN	Hydro	7
Rosewater ⁽²⁾	White County, IN	Wind	102
Indiana Crossroads Wind ⁽²⁾	White County, IN	Wind	302
Dunns Bridge I ⁽²⁾	Jasper County, IN	Solar	265
Indiana Crossroads Solar ⁽²⁾	White County, IN	Solar	200
Cavalry Solar and Storage ⁽³⁾	White County, IN	Solar and Storage	200
Dunns Bridge II ⁽³⁾	Jasper County, IN	Solar and Storage	435
Fairbanks Solar	Sullivan County, IN	Solar	250
Gibson Solar	Gibson County, IN	Solar	200
Total MW Capacity			3,967

⁽¹⁾Represents current net generating capability of each fossil fuel and hydro generating facility. Nameplate capacity is listed for wind and solar generating facilities.

⁽²⁾NIPSCO is the managing partner of these JVs. Refer to Note 4, "Noncontrolling Interests," in the Notes to Consolidated Financial Statements for more information.

⁽³⁾Cavalry Solar and Storage has installed battery storage capacity of 45MW over a four-hour duration. Dunns Bridge II has installed battery storage capacity of 56MW over a four-hour duration.

NIPSCO's 2024 Integrated Resource Plan ("2024 Plan") was submitted to the IURC in December 2024. The 2024 Plan informs future generation investments required to ensure reliability for NIPSCO's customers and incorporated factors such as anticipated load growth from data centers and other economic development opportunities, new EPA emissions rules, and evolving MISO resource accreditation rules. The 2024 Plan maintains the retirement decisions and capacity additions identified in the 2018 and 2021 Integrated Resource Plans and calls for additional generation resources through 2029 to support capacity requirements, along with new gas-fired resources and other capacity resources to support new data center load. In this regard, we executed the ADS Contract in September 2025. As we continue to evaluate additional agreements with data center customers, future integrated resource plans will take this into consideration. Refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of these plans.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, Financial Transmission Rights and ancillary markets. NIPSCO has transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff. NIPSCO generating units are dispatched by MISO which takes into account economics, reliability of the MISO system and unit availability. During the year ended December 31, 2025, NIPSCO generating units, inclusive of its owned renewable generation facilities, were dispatched to meet 55.4% of its overall system load, and the remainder of the overall system load was procured through PPAs and the MISO market.

Competition. Our NIPSCO Electric utility generally has exclusive service areas under Indiana regulations and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources. With respect to data center customers, we face competition from utilities and other energy sources across the United States and abroad. Data center customers consider numerous factors in selecting sites for their operations, including, but not limited to, local weather conditions and patterns, cost of land, local political environment, anticipated ease of zoning and permitting, applicable taxes, and the ability of utilities or power providers to deliver electricity quickly and at scale.

Our NIPSCO Operations are subject to seasonal fluctuations in sales. Revenues from electric operations are more significant during the cooling season, which is primarily from June through September. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - NIPSCO Operations," for additional information.

Regulatory

The regulatory landscape, at both the state and federal levels, continues to evolve, impacting the operations and financial results of our operating companies. Management continually seeks new ways to be more competitive and efficient in this environment, while keeping service and affordability for customers at the forefront. We believe we are, in all material respects, in compliance with applicable laws and regulations at both the state and federal level and do not expect future compliance requirements to have a material impact on our capital expenditures, earnings, or competitive position. While we continue to monitor existing and pending laws and regulations, the impact of regulatory changes cannot be predicted with certainty.

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Rate Case Actions. The following table describes current rate case actions as applicable in each of our jurisdictions. See "Cost Recovery and Trackers" below for further detail on trackers.

(in millions)

Company	Approved ROE	Requested Incremental Revenue	Approved Incremental Revenue	Filing Date	Rates Effective
Approved Rates Cases					
Columbia of Pennsylvania	10.00 %	\$ 110.4	\$ 55.6	March 20, 2025	January 2026
Columbia of Maryland	9.80 %	\$ 10.7	\$ 7.8	September 24, 2024	April 2025
Columbia of Kentucky	9.75 %	\$ 23.8	\$ 14.3	May 16, 2024	January 2025
Columbia of Virginia ⁽¹⁾	9.75 %	\$ 37.2	\$ 28.2	April 29, 2024	October 2024
Columbia of Ohio	9.60 %	\$ 221.4	\$ 68.3	June 30, 2021	March 2023
NIPSCO - Gas ⁽²⁾	9.75 %	\$ 161.9	\$ 120.9	October 25, 2023	August 2024
NIPSCO - Electric ⁽³⁾	9.75 %	\$ 368.7	\$ 257.0	September 12, 2024	July 2025

⁽¹⁾The approved rate case resulted in a black box settlement, representing a settlement to a specific revenue increase but not a specified ROE. The settlement provides use of a 9.75% ROE for future SAVE filings.

⁽²⁾New rates were implemented in 2 steps, with implementation of Step 1 rates effective in August 2024 and Step 2 rates effective in February 2025.

⁽³⁾New rates were implemented in multiple steps, with implementation of Step 1 rates in July 2025 and Step 2 rates effective by March 2026.

FERC. Our service company and operating companies are subject to varying degrees of regulation by the FERC. NiSource Corporate Services files a FERC Form 60 annual report with its financial information as a FERC jurisdictional centralized service company. NiSource also files an annual FERC Form 61 which contains a narrative description of the service company's functions during the prior calendar year.

As natural gas LDCs, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, Columbia of Virginia, Columbia of Kentucky and NIPSCO Gas have limited jurisdictional certificates to transport gas in their respective service territories and into interstate commerce.

As an electric company, NIPSCO Electric has Market Based Rate authority and is a Transmission Owner subject to FERC jurisdiction. NIPSCO files the following reports annually:

- FERC Form 1, which is a comprehensive financial and operating report,
- FERC Form 566, which is a list of its 20 largest purchases of electricity over the past three years,
- FERC Form 715, which is its Annual Transmission Planning and Evaluation Report and the base case power flow data from the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group, which is used by NIPSCO for transmission planning and,
- FERC Form 730, which is NIPSCO's Report of Transmission Investment Activity.

As a Transmission Owner subject to the MISO Transmission Owners Agreement and Tariff, NIPSCO has various FERC jurisdictional obligations such as maintaining its Attachment O formula rates and corresponding protocols. NIPSCO also has FERC approvals to make affiliate transactions between itself and various JVs. NIPSCO's officers, on the electric side, are also subject to FERC's interlocking directorate rules and reporting requirements.

Regulatory Framework. The gas distribution activities of our Columbia and NIPSCO Operations have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include (i) gas supply cost incentive mechanisms for service to their core markets, and (ii) the sale of on-system services in the companies' service territories. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the gas distribution operations utility's system. The incentive mechanisms give the gas distribution operations utilities an opportunity to share in the savings created from such situations as gas purchases made below an agreed upon benchmark price and the remarketing of unused pipeline capacity to reduce overall pipeline costs.

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We recognize that energy efficiency reduces emissions, conserves natural resources and saves our customers money. Our gas distribution companies offer programs such as energy efficiency upgrades, home checkups and weatherization services. The increased efficiency of natural gas appliances and improvements in home building codes and standards contribute to a long-term trend of declining average use per customer. While we are looking to expand offerings so the energy efficiency programs can benefit as many customers as possible, our gas distribution operations utilities have pursued changes in rate design to more effectively match recoveries with costs incurred. Columbia of Ohio has adopted a straight fixed variable rate design for residential and small commercial customers that closely links the recovery of fixed costs with fixed charges. Columbia of Maryland and Columbia of Virginia have regulatory approval for weather and revenue normalization adjustments for certain customer classes, which adjust monthly revenues that exceed or fall short of approved levels. Columbia of Pennsylvania continues to operate its pilot residential weather normalization adjustment and also has a fixed customer charge. This weather normalization adjustment only adjusts revenues when actual weather compared to normal varies by more than 5%. Columbia of Kentucky incorporates a weather normalization adjustment for certain customer classes and also has a fixed customer charge. NIPSCO Gas has also received approval and implemented a weather normalization adjustment for certain of its customer classes. NIPSCO Gas and Electric include a fixed customer charge for residential and small commercial and industrial customer classes.

While increased efficiency of electric appliances and improvements in home building codes and standards have similarly impacted the average use per electric customer in recent years, NIPSCO expects future growth in per customer usage as a result of increasing electric applications, such as electric vehicles. These ongoing changes in use of electricity will likely lead to development of innovative rate designs, and NIPSCO will continue efforts to design rates that increase the certainty of recovery of fixed costs.

Cost Recovery and Trackers. Comparability of our operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs. Certain approved regulatory tracker mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to quickly implement revised rates and recover associated costs.

A portion of the NIPSCO Operations' and Columbia Operations' gas distribution revenue is related to the recovery of gas costs through GCA's, the review of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and confirm the recovery of prudently incurred energy commodity costs supplied to customers.

A portion of the NIPSCO Operations' revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, which is updated quarterly to reflect actual costs incurred to supply electricity to customers.

Political Action

The NiSource Political Action Committee ("NiPAC") provides our employees a voice in the political process. NiPAC is a voluntary, employee driven, and employee funded political action committee and makes bipartisan political contributions to local, state and federal candidates, where permitted and in accordance with established guidelines. Consistent with our commitments and our approach to engagement, the NiPAC leadership committee members evaluate candidates for support on issues important to our business.

Environmental and Safety Matters

PHMSA Legislation and Regulations

To fulfill our vision of being a trusted energy provider, we follow safety practices required by regulations as we implement our SMS. Our SMS serves as the framework to identify and reduce risks and ensure consistent safety processes, procedures and operations across the organization.

As directed by law in the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, PHMSA has proposed and revised various pipeline safety regulations focused on public safety, environmental hazard mitigation, leak detection, methane emissions reduction, and enhanced safeguards for low-pressure distribution systems. Proposed revisions included requirements to detect and repair more leaks, increase survey frequency, and incorporate additional protections to prevent over-pressurization. A final leak detection and repair rule was withdrawn from publication in the Federal Register in January 2025 and the Safety of Gas Distribution Pipelines rulemaking did not progress in 2025.

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We continue to evaluate and monitor PHMSA-related legislation and regulations but cannot predict the impact of changing pipeline safety laws and regulations on our business at this time.

Environmental and Climate Change Issues

In March 2025, the EPA announced it will undertake 31 deregulatory actions to advance the administration's policy priorities as directed by various executive orders. These actions will address multiple existing water, waste, air and climate regulations including, but not limited to, GHG and CCR rules. In July 2025, the EPA proposed rescinding the 2009 Endangerment Finding, the scientific and legal foundation for federal GHG regulations under the Clean Air Act. Additionally, in November 2025, the EPA proposed a rule to extend the compliance deadline for owners and operators to complete closure of their unlined CCR surface impoundments larger than 40 acres from October 2028 to October 2031. On February 6, 2026, the EPA issued a final rule extending compliance deadlines for several provisions of the Legacy CCR Rule. NiSource will continue to monitor these matters and assess the impacts to our business as regulations are proposed and finalized, or as otherwise required by law.

Physical Climate Risks. Increased frequency of severe and extreme weather events associated with climate change could materially impact our facilities, energy sales, and results of operations. We are unable to predict these events. However, we perform assessments of physical risk, including physical climate risk, to our business. More extreme and volatile temperatures, increased storm intensity and flooding, and more volatile precipitation leading to changes in lake and river levels are among the weather events that are most likely to impact our business. Efforts to mitigate these physical risks continue to be implemented.

Transition Climate Risks and Opportunities. We actively engage with and monitor the impact that proposed legislative and regulatory programs related to GHG emissions, at both the federal and state levels, would have on our business. Refer to Item 1A. Risk Factors, "Operational Risks," of this Annual Report on Form 10-K for further detail.

In June 2025, the EPA proposed to repeal GHG emissions standards for fossil fuel-fired power plants that were finalized by the previous federal administration in May 2024. The proposed repeal would eliminate key requirements from the 2024 Carbon Pollution Standards, including capacity factor thresholds and carbon capture and storage (CCS) mandates. If finalized, this action would remove regulatory constraints that could significantly impact NIPSCO's planned gas generation, allowing customers to avoid approximately \$675 million in additional costs as contemplated through the 2024 NIPSCO IRP.

We also continue to monitor evolving state policies related to GHG emissions from our gas distribution companies. The Climate Solutions Now Act of 2022 ("Act") requires Maryland to reduce GHG emissions by 60% by 2031 (from 2006 levels), and it requires the state to reach net zero emissions by 2045. The Maryland Department of the Environment ("MDE") adopted a plan to achieve its 2031 goal and is required to adopt a plan for its 2045 net zero goal by 2030. The Act also enacts a state policy to move to broader electrification of both existing buildings and new construction. In December 2024, the MDE issued final Building Energy Performance Standards, which require net zero direct GHG emissions from large buildings by 2040 with interim targets, or payments of an alternative compliance fee. Under an executive order, Maryland is also developing a Clean Heat Standard and a Zero-Emission Heating Equipment Standard, among other programs, that are intended to transition gas furnaces to electric heat pumps. In December 2025, the Maryland Public Service Commission ("MD PSC") issued proposed regulations with the stated purpose of eliminating "subsidies" for the extension of gas mains and service lines to new residential and commercial customers. According to the MD PSC, these regulations, if finalized, would require persons who request new service to pay the full cost of extending service in order to minimize the risk of future stranded costs for all ratepayers. These proposed regulations were issued in accordance with a June 2025 MD PSC order directing its Staff to prepare such proposed regulations by December 2025. In August 2025, the MD PSC instituted formal proceedings to investigate issues pertaining to long-term natural gas company planning practices. One purpose of these proceedings is to ensure that planning is consistent with Maryland's climate goals. Columbia of Maryland cannot predict the final impact of these policies and proceedings on our business at this time.

Net Zero Goal. In November 2022, we announced a goal of net zero GHG emissions by 2040 covering both Scope 1 and Scope 2 GHG emissions ("Net Zero Goal"). Our Net Zero Goal builds on GHG emission reductions achieved to-date. We plan to achieve our Net Zero Goal primarily through the continuation and enhancement of existing programs, such as retiring and replacing coal-fired electric generation with low- or zero-emission electric generation, ongoing pipe replacement and modernization programs, and deployment of advanced leak-detection technologies. In addition, we plan to advance other low- or zero-emission energy resources and technologies, which may include hydrogen, renewable natural gas, long-duration storage, and/or deployment of carbon capture and utilization technologies, if and when these become technologically and economically feasible. Carbon offsets and renewable energy credits may also be used to support achievement of our Net Zero Goal. As of the end of 2024, we had reduced Scope 1 GHG emissions by approximately 72% from 2005 levels.

Our GHG emissions projections, including achieving a Net Zero Goal, are subject to various assumptions that involve risks and uncertainties, and did not include any assumptions related to data center development and associated load growth. We remain committed to our Net Zero Goal; however, certain of our interim goals may evolve as we assess and respond to business opportunities such as data centers. Achievement of our Net Zero Goal by 2040 will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economically or technologically feasible to deploy at scale, as well as execution of our business plan. Otherwise, our actual results or ability to achieve our Net Zero Goal, including by 2040, may differ materially.

As discussed in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - "Results and Discussion of Operations - NIPSCO Operations," NIPSCO continues to execute its electric generation transition consistent with the preferred pathways identified in its 2018, 2021 and 2024 Integrated Resource Plans. Additionally, as discussed in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - "Executive Summary - Energy Transition" and "Liquidity and Capital Resources - Regulatory Capital Programs," our natural gas distribution companies are lowering methane emissions by replacing aging infrastructure, which also increases safety and reliability for customers and communities.

Human Capital

Human Capital Management Governance and Organizational Practices. The Compensation and Human Capital Committee ("C&HC Committee") of our Board of Directors (the "Board") is primarily responsible for assisting the Board in overseeing our human capital management practices. The C&HC Committee reviews our human capital management function and programs. The review of related procedures, programs, policies and practices allows the committee to make recommendations to management with respect to equal employment opportunity, employee engagement, organizational health, and talent management.

Human Capital Goals and Objectives. We have aligned our human capital goals to achieve overall company strategic and operational objectives by driving an enhanced talent strategy, elevating support for front-line leaders, fostering a culture of rigor and accountability, and strengthening our human resource function. We aspire to be an employer of choice, in part, through embedding inclusion throughout the enterprise and creating an enviable employee experience.

Workforce Composition. As of December 31, 2025, we had 7,668 full-time and 70 part-time active employees (i.e., not interns, not on leave or disability). Of our total workforce, 32% were subject to collective bargaining agreements with various labor unions. These collective bargaining agreements were renegotiated in 2021 and 2023 and expire between March 2026 and June 2027.

We seek to foster an enviable work environment where all employees are energized. In efforts to become an employer of choice, we have developed sourcing strategies to attract and retain the most qualified talent. We are committed to providing equal employment opportunities in each of our companies to all employees and applicants without regard to race, color, religion, national origin or ancestry, veteran status, disability, gender, age, marital status, sexual orientation, gender identity, genetic information, or any protected group status as defined by law. The input provided by our increasingly diverse and inclusive workforce will continue to strengthen our corporate culture as well as drive constructive changes within our company to improve our operational strategies, enhance the quality of the services we provide, and increase revenue. We also offer employee resource groups (ERGs), which are offered to all employees and provide individuals with a shared interest the opportunity to connect.

Talent Attraction. To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate relationships with community and outreach partners. We also target job fairs, while also partnering with local colleges and universities to identify and recruit qualified applicants.

Talent Development and Retention. We offer leadership development programs to enhance the behaviors and skills of our existing and future leaders. In 2025, we had participation from employees of all levels. We also offer extensive technical and non-technical employee development training programs.

We strive to provide promotion and advancement opportunities for employees. We also develop and implement targeted development action plans to increase succession candidate readiness for leadership roles. Additionally, we monitor the risk and potential impact of talent loss and take action to increase retention of top talent.

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Succession Planning. We perform succession planning annually for officer level positions to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Talent is identified, and potential paths of development are discussed, to ensure that employees have an opportunity to build their skills to be well-prepared for future roles. We maintain formal succession plans for our CEO and key officers. The succession plan for our CEO is reviewed by the Nominating and Governance Committee and the succession plans for key officers (other than the CEO) and critical roles are reviewed by the C&HC Committee annually or more frequently as needed.

Employee and Workplace Health and Safety. We have several programs to support employees and their families' well-being. These programs include competitive medical, dental, vision, life and long-term disability programs, including employee health savings account company contributions, family building benefits, telemedicine services, Employee Assistance Program, Integrated Health Management navigation services, and paid time off including wellness, sick/disability, parental leave, and "illness in family" days.

We also have a robust program to support employees, contractors and public safety, which is led by our Chief Safety Officer and is under the oversight of the Safety, Operations, Regulatory and Policy Committee of our Board.

Culture and Engagement. Our culture is another important aspect of our ability to advance our strategic and operational objectives. In addition to the recruiting, development and retention programs described above, we also invest in internal communications programs, including in-person and virtual learning and networking opportunities, as well as regular town hall communications to employees. We measure and monitor organizational health and employee engagement through various channels including employee lifecycle, pulse, and census surveys.

To instill and reinforce our values and culture, we require our employees to participate in regular training on ethics and compliance topics each year, including raising concerns, treating others with respect, preventing discrimination in the workplace, anti-bribery and corruption, data protection, unconscious biases, harassment, conflicts of interest, and how to use the anonymous ethics and compliance hotline. All employees receive training on our Code of Business Conduct annually or more frequently if there is a material change in content. Because of this training and other programs, we have learned from our most recent employee survey that our employees know what ethical violations look like and how to report them. Our Code of Business Conduct is designed to ensure that our employees adhere to legal and regulatory requirements, mitigate risks, and promote ethical behavior. Our ethics program is led by leadership tone at the top, policies and procedures, regular training and communication, monitoring and auditing, and a system for reporting and addressing violations. Our business ethics program, including the employee training program, is reviewed annually by our executive leadership team and the Audit Committee of our Board of Directors.

Our C&HC Committee reviews reports from our Chief Human Resources Officer on employee engagement and corporate culture. Our Board reviews results and action plans related to our enterprise-wide comprehensive employee engagement survey. Our executive leadership team, including our CEO, communicates directly and regularly with all employees on timely ethics topics through electronic messages, coffee chats, and all-employee town hall meetings. These communications emphasize the importance of our values and culture in the workplace.

Available Information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. The SEC maintains an internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers from which investors can electronically access our SEC filings.

We make a number of reports and other information available free of charge on our website, www.nisource.com, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. The information on our website is not, and shall not be deemed to be, a part of this Annual Report on Form 10-K or incorporated into any other filings we make with the SEC.

NI SOURCE INC.INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following is a list of our Executive Officers, including their names, ages, offices held and other recent business experience.

<u>Name</u>	<u>Age</u>	<u>Office(s) Held in Past 5 Years</u>
Lloyd M. Yates	65	President and Chief Executive Officer of NiSource since February 2022 and Director since March 2020
Shawn Anderson	44	Executive Vice President and Chief Financial Officer of NiSource since March 2023 Senior Vice President, Strategy and Chief Risk Officer from May 2022 to March 2023 Senior Vice President and Chief Strategy and Risk Officer from June 2020 to May 2022
Melody Birmingham	54	Executive Vice President and Group President, Utilities of NiSource since March 2025 Executive Vice President and President, NiSource Utilities of NiSource from March 2023 to February 2025 Executive Vice President and Chief Innovation Officer of NiSource from July 2022 to March 2023 Senior Vice President and Chief Administrator Officer of Duke Energy Corporation from May 2021 to June 2022 Senior Vice President, Supply Chain and Chief Procurement Officer of Duke Energy Indiana from 2018 to April 2021
William Jefferson, Jr.	64	Executive Vice President, Chief Operating and Safety Officer of NiSource since May 2024 Executive Vice President, Operations and Chief Safety Officer of NiSource from July 2022 to May 2024 Station Director at STPNOC, Wadsworth, Texas, from 2020 to May 2022 and Vice President in 2022
Michael S. Luhrs	53	Executive Vice President, Technology, Customer and Chief Commercial Officer of NiSource since March 2025 Executive Vice President, Strategy and Risk and Chief Commercial Officer of NiSource from March 2023 to February 2025 Senior Vice President at Alliant Energy from 2022 to March 2023 Vice President at Duke Energy Corporation from 2013 to 2022
Kimberly S. Cuccia	42	Executive Vice President, General Counsel and Corporate Secretary of NiSource since March 2025 Senior Vice President, General Counsel and Corporate Secretary of NiSource from April 2022 to February 2025 Vice President, Interim General Counsel and Corporate Secretary of NiSource from December 2021 to April 2022 Vice President and Deputy General Counsel, Regulatory, of NiSource Corporate Services Company, from January 2021 to December 2021
Melanie B. Berman	55	Executive Vice President, Administration and Chief Human Resources Officer of NiSource since March 2025 Chief Human Resources Officer and Senior Vice President, Administration of NiSource from May 2024 to March 2025 Senior Vice President and Chief Human Resources Officer of NiSource from June 2021 to May 2024 Executive Vice President and Chief Human Resources Officer of The Michaels Companies, Inc. from 2020 to 2021
Gunnar J. Gode	52	Senior Vice President, Chief Accounting & Tax Officer of NiSource since August 2025 Vice President, Chief Accounting Officer and Controller of NiSource from July 2020 to July 2025

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Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the market price of our common stock. Additional risks and uncertainties not presently known to us or that we currently believe are immaterial may also harm our business, financial condition, results of operations, cash flows, and the market price of our common stock.

Risk Factors Summary

The following is a summary of material risks that could adversely affect our business, financial condition, results of operations, cash flows, and the market price of our common stock.

OPERATIONAL RISKS

- We may not be able to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities.
- Our distribution, transmission and generation activities involve a variety of inherent hazards and operating risks, including potential public safety risks.
- We currently conduct and may conduct in the future certain operations through a JV arrangement involving third-party investors that may result in operational impasses or litigation, including business delays as a result of such arrangements.
- Failure to adapt to advances in technology, including alternative energy sources, and changes in laws or regulations to support such advances in technology or alternative energy sources, and our inability to manage such related costs could make us less competitive.
- Increased dependency on technology may hinder our business operations and adversely affect our financial condition and results of operation if such technology fails.
- Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs.
- We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.
- Aspects of the implementation of our electric generation strategy, including the timing of the retirement of our coal generation units or the addition of new generation resources, may be delayed and may not achieve intended results.
- Our capital projects and programs subject us to construction and supply risks, and are subject to governmental oversight and approvals.
- Fluctuations in weather, gas and electricity commodity costs, and economic conditions may impact customer demand.
- Fluctuations in the price of energy commodities or their related transportation costs, or an inability to obtain an adequate, reliable and cost-effective fuel supply may impact our ability to meet customer demand.
- Failure to attract, retain or re-skill an appropriately qualified workforce, and maintain good labor relations, could adversely impact safety, service reliability, and customer satisfaction.
- Failure to effectively manage new initiatives and organizational changes.
- Actions of activist stockholders could negatively affect our business and stock price and cause us to incur significant expenses.
- We outsource certain business functions to third-party suppliers and service providers, and may be impacted by substandard performance or quality by third parties.
- The impacts of a cyber-attack or security breach on any of our or certain third-party technology systems, including operational disruptions and the loss or misuse of confidential and proprietary information and related liability.
- Failure to comply with cybersecurity laws and regulations and the resulting impact on our reputation and business.
- The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, accidents, public health emergencies or other catastrophic events including operational disruptions.
- We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.
- The physical impacts of climate change and the transition to a lower carbon future are impacting our business and could materially adversely affect our results of operations.
- We are subject to operational and financial risks and liabilities associated with the implementation and efforts to achieve our carbon emission reduction goal.

FINANCIAL, ECONOMIC AND MARKET RISKS

- We have substantial indebtedness which could adversely affect our financial condition.
- A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.
- Adverse economic and market conditions, including increases in inflation or interest rates, recession or changes in investor sentiment could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity.
- Most of our revenues are subject to regulation and are exposed to the impact of regulatory rate reviews and proceedings.
- The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity.
- Our business operations are subject to economic conditions in certain industries.
- We are exposed to payment risk with respect to customers and risk that suppliers or counterparties will not perform their contractual obligations.
- We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.
- Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.
- Any future impairments of goodwill resulting in a significant charge to earnings in a future period and negatively impacting our compliance with certain contractual covenants.

LITIGATION, REGULATORY AND LEGISLATIVE RISKS

- The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations may have a material adverse effect on our results of operations, financial position or liquidity.
- A failure to comply with changes in, or new or different interpretations of, the various federal, state and local laws, regulations, tariffs and policies applicable on our business.
- Our businesses are regulated under numerous environmental laws and regulations. The cost of compliance with these laws and regulations, and changes to or additions to, or reinterpretations of the laws and regulations, could be significant, and the cost of compliance may not be recoverable. Liability from the failure to comply with existing or changed laws and regulations could have a material adverse effect on our business, results of operations, cash flows and financial condition.
- Changes in tax laws or the interpretation thereof and challenges to tax positions could adversely affect our financial results.

DATA CENTER OPERATIONS AND STRATEGY RISKS

- Data center growth in our service territories, including a focus on northern Indiana, while providing growth opportunities that enhance our business strategy, provide significant financial, operational, and regulatory risks that must be effectively managed.
- Our construction of the Contract Assets and any generation or transmission assets we develop to support future data center contracts involves significant risks. Construction delays, cost overruns or performance issues with the Contract Assets could reduce our returns under the ADS Contract or other future data center contracts and could require us to obtain additional financing.
- The terms and availability of the significant additional financing required to construct the Contract Assets and any generation or transmission assets we develop to support future data center contracts.
- Pursuit of our partnership with ADS creates significant opportunity costs and reduces our strategic and financial flexibility in the near term.
- The return structure and risk profile of ADS Contract and any future data center contract will differ from those of NIPSCO's traditionally regulated utility operations.
- Our partnership with ADS exposes us to significant customer concentration risk.

OPERATIONAL RISKS

We may not be able to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities.

Operational, financial or regulatory conditions may result in our inability to execute our business plan or growth strategy, including investments related to natural gas and electric distribution and transmission infrastructure investments and our electric generation projects.

Our enterprise-wide transformation roadmap initiatives identify and enable long-term sustainable capability enhancements, cost optimization improvements, technology investments and work process optimization. These initiatives have increased the volume and pace of change within our organization and may not be effective or achieve planned results. These initiatives may also divert the attention of management from other aspects of our business. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain environmental activist groups, investors and governmental entities continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce demand for natural gas and electricity. In addition, we consider acquisitions or dispositions of assets or businesses, JVs, and mergers from time to time as we execute on our business plan and growth strategy. Any of these circumstances could adversely affect our business, results of operations and growth prospects. Even if our business plan, growth strategy, and/or business opportunities are executed, there is still risk of, among other things, human error in maintenance, installation or operations, shortages or delays in obtaining equipment, including as a result of transportation delays and availability, labor availability and performance below expected levels (in addition to the other risks discussed in this section). We may experience supply chain challenges, including labor availability issues, impacting our ability to obtain materials for our gas and electric projects, as well as our ability to ensure timely completion.

Additionally, operational, financial or regulatory conditions or other factors may result in our inability to effectively develop and implement our strategy with respect to the complex business opportunities associated with growing interest in data centers from existing and potential customers. See “Data Center Operations and Strategy Risks” for a discussion of certain such risks.

Our distribution, transmission and generation activities involve a variety of inherent hazards and operating risks, including potential public safety risks.

Our gas distribution and transmission activities and our electric generation, transmission and distribution activities involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, stray electrical voltage, excavation or vehicular damage to our infrastructure, outages, environmental contamination, mechanical problems, damage from weather events, and other incidents, which could cause substantial financial losses. These hazards and risks have resulted and may result in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial business and financial losses. The location of pipeline facilities, including regulator stations, liquefied natural gas and underground storage, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. Hazardous incidents have subjected and may subject us to both civil and criminal litigation or administrative or other legal proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We currently conduct and may conduct in the future certain operations through a JV arrangement involving third-party investors that may result in operational impasses or litigation, including business delays as a result of such arrangements.

We have and may enter into JV arrangements involving third-party investors, including the NIPSCO Minority Interest Transaction and the GenCo Minority Interest Transaction. As part of a JV arrangement, third-party investors may hold certain protective rights that may impact our ability to make certain decisions, restricting our operational and corporate flexibility. The NIPSCO Holdings II LLC Agreement and Generation Holdings II LLC Agreement contain certain such provisions. Any such third-party investors may have interests and objectives which may differ from ours, we may be unable to cause these third

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parties to take action that we believe would be in the JV's best interest, and, accordingly, disputes may arise that may result in operational impasses or litigation, including business delays.

Failure to adapt to advances in technology, including alternative energy sources, and changes in laws or regulations to support such advances in technology or alternative energy sources, and our inability to manage such related costs could make us less competitive.

A key element of our electric business model includes generating power at central station power plants and transmitting that power to customers to achieve economies of scale and produce power at a competitive cost. We continue to transition our generation portfolio in order to implement new and diverse technologies including renewable energy, distributed generation, and energy storage. Advances in technology and potential competition supported by changes in laws or regulations could reduce the cost of electric generation and provide retail alternatives causing power sales to decline and the value of our generating, transmission and distribution facilities to decline, including our ability to recover our prior investments in such facilities.

Our natural gas business model depends on widespread utilization of natural gas for space heating as a core driver of revenues. Alternative energy sources, new technologies or alternatives to natural gas space heating, including cold climate heat pumps and/or efficiency of other products, and potential competition supported by changes in laws or regulations, including potential natural gas bans or restrictions, such as the Department of Energy's furnace rule banning non-condensing gas furnaces, could reduce demand and increase customer attrition, which could impact our ability to recover on our investments in our gas distribution assets.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demand and expectations and evolving industry standards, including environmental impacts associated with our products and services, and to recover all, or a significant portion of, remaining investments in retired assets. A failure by us to effectively adapt to changes in technology, successfully implement such changes, and manage the related costs could harm the ability of our products and services to remain competitive in the marketplace and could have a material adverse impact on our business, results of operations and financial condition. Furthermore, if these changes do not provide the anticipated benefits or meet customer demand and expectations, such failure could materially adversely affect our business model as well as impact our results of operations and financial condition.

Increased dependency on technology may hinder our business operations and adversely affect our financial condition and results of operation if such technology fails.

We use a variety of technological tools and systems including both Company-owned information technology and technological services provided by outside parties. These tools and systems support critical functions including scheduling and dispatching of service technicians, automated meter reading systems, customer care and billing, operational plant logistics, management reporting and external financial reporting. The failure of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded, recovered (including timely recovered), or integrated into other technologies, could hinder our business operations and adversely impact our financial condition and results of operations. Although we have, when possible, developed alternative sources of technology and built redundancy and security into our computer operations, there can be no assurance that these efforts will protect against all potential issues related to the loss or failure of any such technologies.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs.

We face risks associated with aging electric and gas infrastructure. These risks can be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal corrosion, external corrosion, ground movement and stress corrosion and/or cracking. The age of these assets may result in a need for replacement, a higher level of maintenance costs or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets, which in some cases is incomplete, may make the operation of the infrastructure, inspections, maintenance, upgrading and replacement of the assets particularly challenging. Missing or incorrect infrastructure data may lead to (i) difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues, (ii) configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures and (iii) other potential risks related to missing or incorrect infrastructure data. Also, additional maintenance and inspections are required in some instances to improve infrastructure information and records and address emerging regulatory or risk management requirements, resulting in increased costs.

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Supply chain issues related to shortages of materials, labor and transportation logistics may lead to delays in the maintenance and replacement of aging or damaged infrastructure, which could increase the probability and/or impact of a public safety incident. We lack diversity in suppliers of some gas materials. While we have implemented contractual protections with suppliers and stockpile certain materials in inventory, these efforts may not be effective in ensuring that we can obtain adequate emergency supply on a timely basis in each state, that no compromises are being made on quality and that we have alternate suppliers available. The failure to operate our assets as desired could result in interruption of service, major component failure at generating facilities and electric substations, gas leaks and other incidents, and an inability to meet firm service and compliance obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, is impacted by various events and developments affecting our industry and the financial condition and underwriting considerations of insurers. For example, some insurers have discontinued underwriting certain carbon-intensive energy-related businesses such as those in the coal industry or excluded coverage for specific perils such as wildfires, environmental exposures or punitive damage risks. Certain perils, such as cyber liability, are now being excluded from some master policies for property and casualty insurance, requiring, where we have the ability, procurement of additional policies to maintain consistent coverage at an additional cost. Specific natural catastrophe events, such as hail and tornado, may not be covered with the same limits as other perils in certain property policies, as full coverage for these events is unavailable in the marketplace. Insurance coverage may not continue to be available at limits, rates or terms acceptable to us, and we may elect not to carry coverage at the same levels as have been historically procured. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been and in the future may be excluded under the policies. In addition, insurers providing insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

Aspects of the implementation of our electric generation strategy, including the timing of the retirement of our coal generation units or the addition of new generation resources, may be delayed and may not achieve intended results.

We intend to retire the remaining two coal units at R.M. Schahfer Generating Station, two natural gas-fired peaking units at R.M. Schahfer Generating Station, and the coal unit at Michigan City Generating Station. Absent a directive to remain open, we intend to retire the two natural-gas fired peaking units at R.M. Schahfer Generating Station by the end of 2027 and the coal unit at Michigan City Generating Station by the end of 2028. Although we had previously intended to retire them by the end of 2025, the two coal units at R.M. Schahfer Generating Station are currently subject to a federal directive to remain open. These units are being replaced with a diverse, flexible, and scalable mix of incremental resources, including short-term contracted capacity resources, expanded demand side management programs, wind, solar, battery energy storage, and new natural gas peaking resources. Project delays or potential changes with MISO's capacity accreditation of these replacement resources, may also drive us to evaluate additional alternatives to meet our capacity requirements. Macro supply chain issues and U.S. federal policy actions, such as additional federal directives preventing the retirement of these or other assets and the duration of such directives, could create uncertainty around the timing and availability of key input materials necessary to develop and place our electric generation projects in service.

We expect renewable generation, battery energy storage and natural gas generation to be the primary ways in which we will meet our electric generation capacity and reliability obligations to the MISO market and reliably serve our customers when we retire our coal generation capacity. Any delays in the completion of such projects could create significant risks for us to reliably meet our capacity and energy obligations to MISO and to provide reliable and affordable energy to our customers. Delays to the completion dates of our projects could also include delays in the financial return of certain investments and impact the overall timing of our electric generation transition. An inability to secure and deliver on electric generation projects has negatively impacted, and could in the future negatively impact, our generation transition timeline and could negatively impact our achievement of decarbonization goals and reputation.

Our electric generation strategy may require additional investment to meet our MISO obligations and may require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows. In recent years, MISO has implemented new capacity accreditation rules and continues to put forth new plans and proposals relating to its accreditation requirements. Recent MISO accreditation changes have affected generation

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resources, with solar, wind, and battery storage being more significantly impacted than natural gas. It is possible that, under future MISO rules, the capacity accreditation for the capacity resources we construct (potentially including the significant capacity resources we plan to construct to serve ADS and any additional data center customers) will be eliminated or reduced, in which case we would need to replace or supplement the accredited generation capacity we plan to build. We expect that we would need to obtain significant additional debt and equity financing to fund these investments, which may not be available on favorable terms or at all. Although under the terms of the ADS Contract the costs of additional investment in generation resources in response to loss of MISO accreditation would be shared by us and ADS, such investment would be funded initially by us, and our recovery from ADS would occur over an extended period of time. In addition, there can be no guarantee that future data center contracts will contain adequate protections in this regard, or that any such contractual protections would be effective. If we are required to construct additional generation as a result of MISO accreditation changes (and obtain related financing), this could negatively impact our return under the ADS Contract or other data center contracts or otherwise adversely affect our future results and financial condition.

Our capital projects and programs subject us to construction and supply risks, and are subject to regulatory oversight, including requirements for permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas transmission and distribution infrastructure, natural gas storage and other projects, including projects for environmental compliance. In particular, in addition to the capital projects we plan to undertake to support our base business, in connection with the ADS Contract, we expect to construct, through GenCo, 400 MW of new battery storage and a new power generation facility consisting of two 1,300 MW CCGTs, which are expected to reach commercial operation between 2028 and 2032, as well as related transmission and distribution assets. In addition, in order to perform under any further data center contracts, we expect that we will need to develop additional generation and transmission assets, which may be significant. As we undertake these projects, we may be unable to complete them on schedule or at the anticipated costs.

Our ability to construct the currently contemplated generation and transmission assets, and any future generation, transmission or distribution assets in a timely manner and within budget is contingent upon many variables and subject to substantial risks. These variables include, but are not limited to, the ability of key suppliers, general contractors and subcontractors to timely satisfy their obligations under existing or future contracts and in compliance with the terms of such contracts, including the EPC Contracts and equipment supply contracts we have already entered into; the impact of new tariffs, if any, inflation and other trade or economic factors that may impact the cost of supplies and services; any other changes in the availability or costs of materials, equipment or commodities; changes in law or regulation, including environmental compliance requirements; the availability of and ability of our contractors to hire and retain qualified labor and the cost of such labor; delays caused by construction incidents or injuries, work stoppages, poor initial cost estimates and unforeseen engineering issues; the impact of public health emergencies or natural disasters or other severe weather events; capital market conditions, including the availability of credit and our ability to obtain financing on acceptable terms; charges allocated to us by MISO with respect to these assets; the impact of public involvement, intervention or litigation; and our ability to obtain any necessary land rights, easements and/or zoning approvals in a timely manner, or at all.

We are monitoring risks related to increasing delivery lead times for certain construction and other materials, increasing risk associated with the unavailability of materials due to global shortages in raw materials and issues with transportation logistics, and risk of decreased construction labor productivity in the event of disruptions in the availability of materials critical to our gas and electric operations. Our efforts to enhance our resiliency to supply chain shortages may not be effective. We continue to see increasing prices and limited availability associated with certain materials, equipment and products, which may impact our ability to complete major capital projects at the cost and timing that was planned and approved. To the extent that delays occur, costs increase, costs become unrecoverable or recovery is delayed, or we otherwise become unable to effectively manage our costs and timely complete our capital projects, if at all, our business operations, results of operations, cash flows, and financial condition may be adversely affected. In addition, to the extent that delays occur on projects that target system integrity, the risk of an operational incident could increase.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies, including obtaining necessary rights-of-way, easements and transmissions connections, as well as complying with various environmental statutes, rules and regulations, among other items. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, including as a result of public opposition to our existing or planned capital projects or due to new or increased federal, state or local requirements, we may not be able to construct or operate our facilities, we may be forced to incur

additional costs, we may be forced to alter our capital project plans resulting in increased costs and/or delays or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion.

In addition, we are subject to the risk that we may construct or purchase certain projects to capture anticipated future growth (including in connection with potential data center customers), which may not materialize, and may cause the construction to occur over an extended period of time, in which case we may be unable to recover any or all amounts invested in such a project, or receive the anticipated increases in revenue and cash flows resulting from such projects until much later than expected, if at all.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs, and economic conditions impact customer demand.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather resulting from climate change or other factors could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity (which volatility is described in more detail in the below risk factor), whereby usage declines with increased costs which could affect our financial results. Rising gas costs could heighten regulator and stakeholder sensitivity relative to the impact of base rate increases on customer affordability. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as recession, inflation, unemployment, demand and consumer confidence. Therefore, prevailing economic conditions affecting our customers may in turn affect demand and our financial results.

Fluctuations in the price of energy commodities or their related transportation costs, or an inability to obtain an adequate, reliable and cost-effective fuel supply may impact our ability to meet customer demand.

Our current electric generating depends on coal and natural gas for fuel, and our gas distribution operations purchase and resell a portion of the natural gas we deliver to our customers. These energy commodities are subject to price fluctuations and fluctuations in associated transportation costs. We use physical hedging through the use of storage assets and use financial products in certain jurisdictions in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions we operate in order to fully recover the commodity costs incurred in selling energy to our customers. While we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation and storage facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to our customers. If transportation is disrupted, if capacity is inadequate or if supply is interrupted, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

Failure to attract, retain or re-skill an appropriately qualified workforce, and maintain good labor relations, could adversely impact safety, service reliability, and customer satisfaction.

We face increased competition for talent which may result in longer hire times or increased cost due to the competitive nature of certain positions.

We operate in an industry that requires many of our employees and contractors to possess unique technical skill sets. An aging workforce without appropriate replacements, the mismatch of current skill sets to future needs, the unavailability of talent for internal positions and the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. For example, certain skills, such as those related to construction, maintenance and repair of transmission and distribution systems, are in high demand and have a limited supply. Current and prospective employees may determine that they do not wish to work for us due to market, economic, employment or other conditions, including those related to organizational changes as described in the risk factor below.

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Further, as part of our strategic plan, which includes enhanced technology, transmission and distribution investments, and a reduction in reliance on coal-fired generation, we will need to attract and retain personnel that are qualified to implement such a strategy and may need to retrain or re-skill certain employees to support our long-term objectives. Additionally, successful implementation of our strategic plan is dependent on our ability to recruit and retain key executive officers to oversee our progress.

A significant portion of our workforce is subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis with some companies having multiple bargaining agreements, which may span different geographies. Any failure to reach an agreement on new labor contracts or to renegotiate these labor contracts might result in labor disruptions, strikes or significant negotiated wage or benefit increases. Although we maintain workforce continuity plans, our workforce continuity plans may not be effective in avoiding work stoppages that may result from labor negotiations or mass resignations. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

Failure to attract, retain, or re-skill qualified employees, including the ability to transfer significant internal historical knowledge and expertise to new employees, could result in a loss of momentum, loss of high-level employees to our peers and could materially adversely affect our business, results of operations, cash flow and financial condition. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory labor relations, safety, service reliability, and customer satisfaction, our results of operations could be adversely affected.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.

In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. The organizational changes from our transformation initiatives put pressure on employees due to the volume and pace of change and, in some cases, the loss of personnel. Front-line workers are being impacted by the variety of process and technology changes that are currently in progress.

If we are unable to make decisions quickly, assess our opportunities and risks, and successfully implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers, employees and stockholders may be negatively impacted.

Actions of activist stockholders could negatively affect our business and stock price and cause us to incur significant expenses.

We may be subject to actions or proposals from activist stockholders or others that may not be aligned with our long-term strategy or the interests of our other stockholders. Our response to suggested actions, proposals, director nominations and contests for the election of directors by activist stockholders could disrupt our business and operations, divert the attention of our board of directors, management and employees, and be costly and time-consuming. Potential actions by activist stockholders or others may interfere with our ability to execute our strategic plans; create perceived uncertainties as to the future direction of our business or strategy; cause uncertainty with our regulators; make it more difficult to attract and retain qualified personnel; and adversely affect our relationships with our existing and potential business partners. Any of the foregoing could adversely affect our business, financial condition and results of operations. Also, we may be required to incur significant fees and other expenses related to responding to stockholder activism, including for third-party advisors. Moreover, our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any stockholder activism.

We outsource certain business functions to third-party suppliers and service providers, and may be impacted by substandard performance or quality by third parties.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Like other companies in the utilities industry, we outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services, corporate and other areas. We have seen, and may see in the future, slowing deliveries from suppliers and in some cases materials and labor shortages. In addition to delays and unavailability, at times, outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry

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standards), interruption of service, accidents, or reputational harm, which could negatively impact our business, financial condition and results of operations. The nature of indirect supply chain, including a potential lack of control or certain visibility into sourcing by vendors, may also impact our ability to serve customers in a safe, reliable and cost-effective manner. These risks include the risk of operational failure, reputation damage, disruption due to new supply chain disruptions, exposure to significant commercial losses and fines and poorly positioned and distressed suppliers. If delayed deliveries and shortages or any other difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers, or employees.

A cyber-attack or security breach on any of our or certain third-party technology systems, including but not limited to information systems, infrastructure, software and hardware, upon which we rely may adversely affect our ability to operate, could lead to a loss or misuse of confidential and proprietary information, or potential liability.

We are reliant on technology to run our business, which is dependent upon technology systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity; operation of our gas pipeline facilities; and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cybersecurity risks that all large corporations face (e.g., ransomware, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting electric grid and natural gas infrastructure as well as sensitive and confidential customer and employee information. Deployment or adoption of new or emerging business technologies, including artificial intelligence, Internet of Things (IoT) devices, and cloud-based platforms, increased reliance on third-party vendors, cloud service providers and software supply chains, along with maintaining legacy technology, heightens our exposure to risks outside of our control and represents a large-scale opportunity for attacks on our information systems and confidential customer and employee information, as well as on the integrity of the electric grid and the natural gas infrastructure. Increasing large-scale corporate cyber-attacks in conjunction with more sophisticated threats continue to challenge utility companies. Additionally, international conflicts, as well as increased surveillance activity from global threat actors, has increased the likelihood of a cyber-attack or security breach on critical infrastructure systems.

Additionally, our information systems could experience sophisticated, cyber-attacks or security breaches by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such cyber-attacks or security breaches, our cybersecurity program does not prevent all breaches, cyber-attack or security breach incidents. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have experienced, and expect to continue to experience, cybersecurity intrusions and attacks or security breaches to our information systems. To our knowledge, none of these intrusions or attacks have resulted in a material cybersecurity intrusion or data breach. The risk of a disruption or breach of our operational technology, or the compromise of the data processed in connection with our operations, through cybersecurity breach or ransomware attack has increased as attempted cyber-attacks or security breaches have advanced in sophistication and number around the world. Technological complexities combined with advanced cyber-attack or security breach techniques, lack of cybersecurity hygiene and human error can result in a cybersecurity incident, such as a ransomware attack. Supplier non-compliance with cybersecurity controls can also result in a cybersecurity incident. We are aware of vendor cybersecurity incidents that have impacted our business, although no such events have had a material impact. Cyber-attacks or security breaches can occur at any point in the supply chain or with any suppliers, and future supplier non-compliance with cybersecurity controls could result in material cybersecurity incidents. In addition, we use unmanned aircraft systems (UAS) or drones in our business operations. UASs are also being used for malicious activities and the cybersecurity risk in connection with operating UASs is increasing.

In addition, we collect and retain personally identifiable information of our customers and employees. Customers and employees expect that we will adequately protect their personal information.

A cybersecurity breach of our information systems or operational technology, or a cybersecurity breach of the information systems of our customers, suppliers or others with whom we do business, could, among other things, (i) adversely impact our ability to safely and reliably deliver electricity and natural gas to our customers through our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability and gas flow standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and

claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition and/or results of operations. Although we do maintain cybersecurity insurance, it is possible that such insurance will not adequately cover any losses or liabilities we may incur as a result of a cybersecurity incident.

Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows.

The legal and regulatory environment surrounding cybersecurity and privacy is increasingly demanding. As cyber-attacks or security breaches are becoming more sophisticated, critical infrastructure assets, including pipelines and electric infrastructure, may be specifically targeted. In November 2024, the TSA issued a Notice of Proposed Rulemaking (NPRM) that would mandate cyber risk management and reporting requirements for the pipeline industry. Such directives or additional legal requirements may require expenditure of significant additional resources to respond to cyber-attacks or security breaches, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Increased costs and the operational impacts of compliance and changes in cybersecurity requirements, including any failure to comply with government regulations or any failure in our cybersecurity protective measures may result in enforcement actions, all of which may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates.

The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, accidents, public health emergencies or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a hurricane, tornado, wildfire, flood, or other major weather event, or terrorist attack, acts of war, international military invasions, including the political and economic disruption and uncertainty related to such terrorist attack, acts of war, or international military invasions, civil unrest, accident, public health emergency (e.g. pandemic), or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from tornadoes, hurricanes and remnants of hurricanes and other events of this nature. Also, companies in our industry face a heightened risk of exposure to and have experienced acts of terrorism and vandalism. Our electric and gas physical infrastructure may be targets of physical security threats or terrorist activities that could disrupt our operations. We have increased security given the current environment and may be required by regulators or by the future threat environment to make investments in security that we cannot currently predict. In addition, supply chain constraints could impact our ability to timely restore services. The occurrence of such events could materially adversely affect our business, financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. As a result, the amount and scope of insurance coverage maintained against losses resulting from any such event may not be sufficient to cover such losses or otherwise adequately compensate for any business disruptions that could result.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the actual or perceived reliability or affordability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage, physical or cybersecurity incidents, or other unanticipated events, as well as our own or third parties' actions or failure to act. We are subject to prevailing labor markets and potential high attrition, which may impact the speed of our customer service response. We are also facing supply chain challenges, the impacts of which may adversely impact our reputation in several areas as described elsewhere in these risk factors. We are also subject to adverse publicity related to actual or perceived environmental practices or impacts, including our ability to meet the challenges posed by climate change and achieve our carbon emission reduction goals, as well as negative opinions regarding the appropriateness of such goals. If customers, legislators or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. The foregoing may have adverse effects on our business, results of operations, cash flow and financial condition.

The physical impacts of climate change and the transition to a lower carbon future are impacting our business and could materially adversely affect our results of operations.

Climate change is exacerbating risks to our physical infrastructure by increasing the frequency of extreme weather, including temperature stresses to our electric and gas systems and equipment and storms and floods that damage infrastructure. In addition, climate change is likely to cause lake and river level changes that affect the manner in which services are currently

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provided and droughts or other limits on water used to supply services, and other extreme weather conditions. We have adapted and will continue to evolve our infrastructure and operations to meet current and future needs of our stakeholders. With higher frequency of these and other possible extreme weather events it may become more costly for us to safely and reliably deliver certain products and services to our customers. As our generation profile increases geographically, it is potentially more vulnerable to certain weather hazards, thereby increasing the frequency of weather impacts to overall electric reliability. Furthermore, in certain locations, our generation assets are geographically concentrated. Therefore, a localized weather or hazard impacting such a location could have a disproportionate cost and adverse effect on our ability to deliver certain products and services. Some of these costs may not be recovered. To the extent that we are unable to recover those costs, or if higher rates arising from recovery of such costs result in reduced demand for services, our future financial results may be adversely impacted. Further, as the intensity and frequency of significant weather events increases, insurers may reprice or remove themselves from insuring risks for which the company has historically maintained insurance, resulting in increased cost or risk to us.

Our strategy may be impacted by policy and legal, technology, market and reputational risks and opportunities that are associated with the transition to a lower-carbon economy, as disclosed in other risk factors in this section. As a result of increased awareness regarding climate change, coupled with economic considerations, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and regulations restricting, or imposing fees on, emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, which may result in less demand for our services. As these technologies become a more cost-competitive option, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of our systems and services, which may result in, among other things, our facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels could result in a significant impact on our electric generation and natural gas businesses in the future.

We are unable to forecast the future of commodity markets. Some of our generation is dependent on natural gas and coal, and we pass through the costs for these energy sources to our customers. In addition, in our gas distribution business, we procure natural gas on behalf of certain customers, and we pass through the actual cost of the gas consumed. Diminished investor interest in funding fossil fuel development could reduce the amount of exploration and production of natural gas or coal, or investment in gas transmission pipelines. Reduced production and transportation of natural gas could, in the long-term, lead to supply shortages leading to baseload generation outages. Given that we pass through commodity costs to customers, this could also create the potential for regulatory questions resulting from increased customer costs, reduced fossil fuel investment, due to evolving investor sentiment, could lead to higher commodity prices and shortages impacting our generation and our reputation with regulators. Conversely, demand for our services may increase as a result of customer changes in response to climate change. For example, as the utilization of electric vehicles increases, demand for electricity may increase, resulting in increased usage of our systems and services.

Any negative views with respect to our environmental practices or our ability to meet the challenges posed by climate change from regulators, customers, investors or legislators could not only harm our reputation, but could adversely affect the perceived value of our products and services. Changes in policy to combat climate change, and technology advancement, each of which can also accelerate the implications of a transition to a lower carbon economy, may materially adversely impact our business, financial position, results of operations, and cash flows. For example, Maryland is considering policies related to the planning, practices, and future operations of natural gas suppliers in its state which could impact our business in the future.

We are subject to operational and financial risks and liabilities associated with the implementation and efforts to achieve our carbon emission reduction goal.

In November 2022, we announced our goal of reaching net zero Scope 1 and 2 greenhouse gas emissions by 2040 (the “Net Zero Goal”). Achieving the Net Zero Goal will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economically or technologically feasible to deploy at scale, of which, the impacts and costs are not currently fully understood. NIPSCO’s electric generation transition, which is outlined in the 2024 Plan, is a key element of the Net Zero Goal. Our analysis and plan for execution requires us to make a number of assumptions. These underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of our underlying assumptions prove incorrect, our actual results and ability to achieve our emissions goal could differ materially from our expectations. Certain of the assumptions that could impact our ability to meet our emissions goal include, but are not limited to: the accuracy of current emission measurements; the ability to complete and implement generation alternatives to NIPSCO’s coal generation and retire NIPSCO’s coal facilities; the ability to implement our modernization plans

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for our natural gas pipelines and facilities, including construction of new pipelines and facilities; customer demand and capacity needs remaining in line with current expectations, including impacts from energy efficiency and technological innovation and adoption of alternative energy sources; the ability to effectively manage emissions associated with electric generation to serve growth and data center development; the ability to manage costs and supply chain risks associated with construction of electric and natural gas assets; technological innovation and costs of energy generation technologies such as wind, solar, nuclear thermal and energy storage, and of carbon abatement technologies such as carbon capture solutions; stakeholder support for these technologies; regulatory approval and the terms of such approvals; impacts of potential future environmental regulations or legislation, including potential GHG pricing regimes such as a carbon tax or methane fee; the price, availability and regulation of carbon offsets; and the price of natural gas and alternative fuels such as hydrogen. Any negative opinions with respect to these goals or our environmental practices, including our ability to meet the challenges posed by climate change and our ability to achieve our carbon emission reduction goals, or a scaling back of these goals, formed by regulators, customers, investors or legislators could harm our reputation and have an adverse effect on our financial condition.

FINANCIAL, ECONOMIC AND MARKET RISKS

We have substantial indebtedness which could adversely affect our financial condition.

Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of \$16,213.5 million outstanding as of December 31, 2025. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;
- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations. Additionally, non-compliance with debt covenants could adversely affect our ability to obtain future borrowings. Any and all of the above could materially adversely affect our business, financial condition, results of operations, and liquidity.

In addition, we expect to incur significant additional indebtedness in order to construct the generation and transmission assets needed to serve ADS and any future data center customers. See “Data Center Operations and Strategy Risks—We will be required to obtain significant additional financing in order to construct the Contract Assets and any generation or transmission assets we develop to support future data center contracts. Such financing may not be available on favorable terms, if at all.” and “—Pursuit of our partnership with ADS creates significant opportunity costs and reduces our strategic and financial flexibility in the near term.” for a discussion of certain risks relating to this anticipated additional indebtedness.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our actual or perceived business risk (including increasing data center operations as compared to traditional utility operations), capital structure, earnings profile, liabilities, business strategy, and overall shifts in the economy or business environment. We are committed to maintaining investment grade credit ratings; however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

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Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if our credit ratings (including the standalone credit ratings of certain of our subsidiaries) drop below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2025, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately \$150.2 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries’ credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of our indebtedness would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such increase may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower our share price and result in greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

Adverse economic and market conditions, including increases in inflation or interest rates, recession or changes in investor sentiment could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity.

Deteriorating, sluggish or volatile economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce our revenue or growth rate and increase operating costs. A continued economic downturn or recession, or slowing or stalled recovery from such economic downturn or recession, may have a material adverse effect on our business, financial condition, or results of operations.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on the issuance of long-term debt and equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. There may be external factors such as inflation, monetary policy or other market conditions which could impact our cost of borrowing and could make it more difficult to obtain financing for our operations or investments on favorable terms. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in interest rates, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. For example, because NIPSCO’s current generating facilities partially rely on coal for its operations, certain financial institutions may choose not to participate in our financing arrangements. In addition, investors may choose to sell or choose not to purchase our stock due to environmental, social and governance or sustainability concerns. Reduced access to capital markets, increased borrowing costs, and/or lower equity valuation levels could reduce future earnings per share and cash flows. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings.

We may face limits on our ability, or inability, to access credit and capital markets or may experience significant increases in the cost of capital, which could limit our ability to implement or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

Most of our revenues are subject to regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact our revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs and investments. As described in more detail in the risk factor below, the outcomes of these proceedings are uncertain, potentially lengthy and could be influenced by many factors, some of which may be outside of our control, including the cost of providing service, the regulators’ view as to the necessity of our expenditures, regulatory interpretations, customer intervention, economic conditions, the political environment and customer affordability. Further, the rate orders are subject to appeal, which creates additional uncertainty as to the rates that will ultimately be allowed to be charged for services.

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The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity.

The rates that our electric and natural gas companies charge their customers are determined by their state regulatory commissions and by the FERC. These state regulatory commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. The FERC also regulates the transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters, including reliability standards through the North American Electric Reliability Corporation (NERC). Further, NIPSCO's and GenCo's operations under the ADS Contract will be, and under future data center contracts are expected to be, regulated by the IURC in a different way from the regulatory mechanisms applicable to NIPSCO's historical operations. See "Data Center Operations and Strategy Risks" for a discussion of certain such risks.

Under state and federal law, our electric and natural gas companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their prudently incurred operating and capital costs and a reasonable rate of return on invested capital, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Our electric and natural gas companies are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. Each of these companies prepares and submits periodic rate filings with their respective regulatory commissions for review and approval, which allows for various entities to challenge our current or future rates, structures or mechanisms and could alter or limit the rates we are allowed to charge our customers. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing interests. Any change in rates, including changes in allowed rate of return, are subject to regulatory approval proceedings that can be contentious, lengthy, and subject to appeal. This may lead to uncertainty as to the ultimate result of those proceedings. Established rates are also subject to subsequent prudency reviews by regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including cost recovery mechanisms. The ultimate outcome and timing of regulatory rate proceedings could have a significant effect on our ability to recover costs or earn an adequate return. Adverse decisions in our proceedings or changes to the related regulatory rules or processes could adversely affect our financial position, results of operations and cash flows.

There can be no assurance that regulators will approve the recovery of all operating and capital costs incurred by our electric and natural gas companies, including, but not limited to, costs for construction, operation and maintenance, and compliance with current and future changes in environmental, federal pipeline safety, critical infrastructure and cybersecurity laws and regulations. Further, we face regulatory challenges when our electric and gas companies seek regulatory recovery of increases to materials and other costs as a result of inflationary pressures, including accounting for inflationary pricing in plans and assumptions and ensuring there is a regulatory recovery model. There is debate among regulators and other stakeholders over how to transition to a decarbonized economy and prudency arguments relative to investing in natural gas assets when the depreciable life of the assets may be shortened due to electrification. The inability to recover a significant amount of operating or capital costs could have an adverse effect on our financial position, results of operations and cash flows.

Changes to rates may occur at times different from when costs are incurred. Additionally, catastrophic events at other utilities could result in our regulators and legislators imposing additional requirements that may lead to additional costs or operational requirements for our companies.

In addition to the risk of disallowance of incurred costs, regulators may also impose downward adjustments in a company's allowed ROE, as well as assess penalties and fines. Regulators may reduce ROE to mitigate potential customer bill increases due to items unrelated to capital investments. These actions would have an adverse effect on our financial position, results of operations and cash flows.

For a discussion of the regulation of our operations related to serving data center customers and relationships with data center customers that are served by generation assets constructed by GenCo and related risks, see "Data Center Operations and Strategy Risks—The return structure and risk profile of ADS Contract and related development of the Contract Assets differ from those of NIPSCO's traditionally regulated utility operations. Any future data center contracts we enter into are expected to have a comparable structure and risk profile."

Our electric business is subject to mandatory reliability and critical infrastructure protection standards established by NERC and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. In addition, compliance with PHMSA regulations, including the expected final ruling around leak detection and repair

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requirements could subject our gas utilities to higher operating costs and divert business resources from other activities in order to remain compliant. If our businesses are found to be in noncompliance, we could be subject to sanctions, including substantial monetary penalties, or damage to our reputation.

Changes in tax laws, as well as the potential tax effects of business decisions, could negatively impact our business, results of operations (including our expected project returns from our planned renewable energy projects), financial condition and cash flows.

Our business operations are subject to economic conditions in certain industries.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where our businesses operate. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, are impacted by economic downturns and recession; geographic or technological shifts in production or production methods; and other changes in consumer demand, including due to a preference for environmentally friendly products and practices. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, inflation and increasing costs, government and societal pressure to decarbonization, and fluctuating demand for its products.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Management Policy, involves judgment by our employees and is based on an evaluation of customer, supplier, or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions impacting these credit risk exposures could result in an increase in defaults by customers, suppliers and counterparties. We are also exposed to the risk that due to adverse economic conditions one or more suppliers or counterparties may fail or delay the performance of their contractual obligations, such risks could negatively impact our business, financial condition and cash flow.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries, which are separate and distinct legal entities. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock, if any, is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which could fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefit plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or longer life expectancy assumptions, as well as voluntary early retirements. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expenses could negatively impact our results of operations and financial position.

We have significant goodwill. Any future impairments of goodwill could result in a significant charge to earnings in a future period and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying value. Goodwill is also tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price

or market capitalization below book value, indicate that the carrying value may not be recoverable and results in a significant charge to earnings. We cannot predict the timing, magnitude, or duration of such changes. In general, an impairment of goodwill would not be recoverable, in which case we may record a non-cash impairment charge, which could materially impact our results of operations and financial position.

A significant impairment charge in the future could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our revolving credit facility, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2025, the ratio was 51.0%.

LITIGATION, REGULATORY AND LEGISLATIVE RISKS

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations may have a material adverse effect on our results of operations, financial position or liquidity.

We are, or may be, involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, the most significant of which are summarized in, Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements. While we maintain insurance, it may not cover all costs or expenses incurred relating to litigation. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies and a failure to comply with changes in, or new or different interpretations of, such laws, regulations, tariffs and policies could have an adverse impact on our business.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies, including, but not limited to, those relating to natural gas pipeline safety, employee safety, the environment and our energy infrastructure. In particular, we are subject to significant federal, state and local regulations applicable to utility companies, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Existing laws, regulations, tariffs and policies may be revised or become subject to new interpretations, and new laws, regulations, tariffs and policies may be adopted or become applicable to us and our operations. In some cases, compliance with new or different laws, regulations, tariffs and policies increases our costs or risks of liability. Supply chain constraints, both direct and indirect, including but not limited to material or labor shortages, may challenge our ability to remain in compliance with these laws, regulations, tariffs and policies and operate our business in a compliant manner. If we fail to comply with laws, regulations and tariffs applicable to us or with any changes in or new interpretations of such laws, regulations, tariffs or policies, our financial condition, results of operations, regulatory outcomes and cash flows may be materially adversely affected.

Our businesses are regulated under numerous environmental laws and regulations. The cost of compliance with these laws and regulations, and changes to or additions to, or reinterpretations of the laws and regulations, could be significant, and the cost of compliance may not be recoverable. Liability from the failure to comply with existing or changed laws and regulations could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, leak detection and repair, GHG and waste products such as CCR. Compliance with these legal obligations require us to make significant expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, that failure or harm may result in the assessment of civil or criminal penalties and damages against us, injunctions to remedy the failure or harm, and the inability to operate facilities as designed and intended. Further, failing to comply with such laws and regulations or a determination that we have caused damage to the environment or persons, could result in reputational damage.

Existing environmental laws and regulations may be revised and new laws and regulations may be adopted or become applicable to us, with an increasing focus on the impact of coal and natural gas facilities that may result in significant additional expense and operating restrictions on our facilities, which may not be fully recoverable from customers and could materially affect the continued economic viability of our facilities.

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An area of significant uncertainty and risk are potential changes to the laws concerning emission of GHG. While we have set a Net Zero Goal and continue to execute our plan to reduce our GHG emissions by the increased sourcing of renewable energy, priority pipeline replacement, leak detection and repair, and other methods, GHG emissions are anticipated to be associated with energy delivery for many years. Future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Another area of significant uncertainty and risk are the regulations concerning CCR. The EPA has issued regulations and may promulgate additional regulations concerning the management, storage, use and disposal of CCRs. NIPSCO is also incurring or will incur costs associated with closing, corrective action, and ongoing monitoring of certain CCR impoundments. Further, a release of CCR to the environment could result in remediation costs, penalties, claims, litigation, increased compliance costs, and reputational damage.

We have a pending application with the EPA to continue operation of a CCR impoundment that is tied to operation of R.M. Schahfer Generating Station Units 17 and 18, which are operating under a 202(c) order. The EPA has proposed a rule that would extend the deadline to close this CCR impoundment from 2028 to 2031. In the event that approval of this application is not obtained, or the rule is not finalized and implemented, future operations could be impacted, as well as NIPSCO's ability to comply with certain EPA requirements.

The actual future expenditures to achieve environmental compliance depends on many factors, including the nature and extent of impact, the method of remediation or improvement, the cost of raw materials, contractor costs, and requirements established by environmental authorities. Changes or increases in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

Changes in tax laws or the interpretation thereof and challenges to tax positions could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted or interpreted by any of these governmental authorities. The IRA imposed a 15 percent minimum tax rate on book earnings for corporations with higher than \$1 billion of annual income, along with a 1 percent excise tax on corporate stock repurchases while providing tax incentives to promote various clean energy initiatives. Our NIPSCO subsidiary's renewable portfolio is eligible for tax credits associated with the investment in renewable generation assets and production of power from those assets. Statutory changes, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

DATA CENTER OPERATIONS AND STRATEGY RISKS

Data center growth in our service territories, including a focus on northern Indiana, while providing growth opportunities that enhance our business strategy, provide significant financial, operational, and regulatory risks that must be effectively managed.

As we continue to evaluate new business opportunities presented by the data center development in our territories, including a focus on northern Indiana, we face a variety of challenges including accurately predicting future power needs of data centers due to rapidly changing technology and market dynamics, managing the potential power demand, generation sources, and transmission capabilities to meet potential load growth from any data center customer, financing the capital investment needed to build and maintain the necessary infrastructure to support data center development, obtaining permitting and siting approval for necessary infrastructure (which may encounter significant local opposition), managing the possible environmental impact of the potential increased power demand while remaining focused on our Net Zero Goal, and evaluating and complying with evolving regulations related to data center development. In addition, our ADS Contract requires us to invest significant capital to develop generation sources and transmission capabilities before we receive the full return on the capital invested, and it is likely that any future data center contracts we enter into similarly will require significant investment before receiving returns. In addition, we face challenges in predicting the demand of potential data center customers in our service territories. It is possible that we may overestimate such demand, causing us to invest in generation and transmission assets in excess of those needed to serve data center customers. If we are not able to utilize such assets to serve other customers, this could negatively affect our

reputation, cash flows, financial position and/or results of operations. We also may underestimate the potential demand of data center customers, in which case we may not be able to develop necessary generation and transmission assets within a timeframe that is acceptable to potential customers, resulting in the loss of potentially profitable opportunities. We must effectively manage these financial, operational and regulatory risks.

Our construction of the Contract Assets and any generation or transmission assets we develop to support future data center contracts involves significant risks. Construction delays, cost overruns or performance issues with the Contract Assets could reduce our returns under the ADS Contract or other future data center contracts and could require us to obtain additional financing.

In connection with the ADS Contract and any future data center contracts, we expect to construct significant generation and transmission assets. Our ability to construct such assets in a timely manner and within budget is contingent upon many variables and subject to substantial risks. See “Operational Risks— Our capital projects and programs subject us to construction and supply risks, and are subject to regulatory oversight, including requirements for permits, approvals and certificates from various governmental agencies” for additional information. Our return under the ADS Contract will be, and our return under future data center contracts is expected to be, affected by our ability to construct, develop and place into service these assets on time or at all and consistent with initial cost estimates, as well as the performance of these assets once constructed and placed into service.

Under the ADS Contract, if the Contract Assets are delivered into service late or do not achieve certain other performance-related milestones, ADS is entitled to liquidated damages, which would be offset against NIPSCO’s billings to ADS and reduce the rate of return earned under the ADS Contract. In addition, our actual costs to construct the Contract Assets may exceed the budget contemplated by the ADS Contract, which could result from delays in construction or from other factors. Any such cost overruns will need to be funded initially by us, either through our cash flows from operating activities or additional debt or equity financing. Although our EPC contracts provide certain protections against cost overruns under those contracts, and any excess costs not recoverable through the EPC contracts are to be shared by us and ADS, any recoveries from our EPC contractors and/or ADS would occur over an extended period of time. The need for us to fund these expenses in the first instance may reduce our ability to use our operating cash flows for other purposes or may require us to obtain additional debt or equity financing, which may not be available on favorable terms or at all. These costs, if incurred, could negatively impact our return under the ADS Contract or adversely affect our future results and financial condition. In addition, we expect that construction delays, performance shortfalls or cost overruns in connection with construction of generation and transmission assets supporting any future data center contracts could similarly have a negative effect on our return under such contracts and our financial condition.

We will be required to obtain significant additional financing in order to construct the Contract Assets and any generation or transmission assets we develop to support future data center contracts. Such financing may not be available on favorable terms, if at all.

In order to finance the construction of the Contract Assets, as well as any generation and transmission assets we develop to support future data center contracts, we expect to incur significant additional long-term debt and issue additional equity in NiSource, in addition to the financing we otherwise would seek to support investments in our existing businesses and refinance existing indebtedness. The NIPSCO Holdings II LLC Agreement and Generation Holdings II LLC Agreement will allow for additional capital contributions from affiliates of Blackstone to NIPSCO Holdings II and Generation Holdings II in connection with such Blackstone affiliates’ minority interest investments in those entities. In addition, we may consider other funding sources, structures, or partnerships such as JVs or off-balance sheet arrangements such as BTAs, as market conditions and strategic considerations evolve, or as may be necessary to support maintenance of our investment grade credit ratings. The amount of additional long-term debt or NiSource equity needed to support construction of the Contract Assets and any generation and transmission assets to support future data center contracts could increase, potentially significantly, from our current expectations if we experience construction delays or cost overruns.

External factors such as inflation, monetary policy or other market conditions could impact our cost of borrowing and could make it more difficult to obtain the financing that is required to construct the Contract Assets and any generation and transmission assets we develop to support future data center contracts on favorable terms, or at all. The issuance of additional debt could negatively impact our credit ratings and overall cost of capital, which could in turn adversely affect our future results and liquidity. In addition, an economic downturn or uncertainty, market turmoil, changes in interest rates, changes in tax policy, challenges faced by financial institutions, or a change in investor sentiment toward us or the utilities industry or the cloud-computing, artificial intelligence and data center industry generally could adversely affect our ability to raise the necessary capital. Reduced access to capital markets, increased borrowing costs, and/or lower equity valuation levels could jeopardize our

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ability to complete construction of the Contract Assets or any generation and transmission assets we develop to support future data center contracts on-time and within budget, and could reduce future earnings per share and cash flows. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings.

Pursuit of our partnership with ADS creates significant opportunity costs and reduces our strategic and financial flexibility in the near term.

We expect to incur significant indebtedness to fund our construction of the Contract Assets. Doing so will reduce our ability to incur further indebtedness to pursue other strategic opportunities, such as partnerships with other large data center customers or strategic mergers and acquisitions, while at the same time maintaining our investment grade credit ratings, which may require us to rely to a greater degree on equity financing in connection with future data center contracts and also may increase our reliance on equity financing for future investments in our existing traditionally regulated utility business, each of which could lead to substantial dilution of our existing shareholders. In addition, our credit rating agencies consider the percentage of our business comprised of traditionally regulated utility operations in their analysis of our credit quality.

In addition to these factors relating to our financing and credit ratings, our partnership with ADS is expected to employ a significant amount of our existing excess transmission infrastructure, which will limit our ability to use these assets for other opportunities, including additional data center opportunities. Furthermore, effectively overseeing the construction and financing of the Contract Assets will require significant time and attention of our management, which could detract from their oversight of our existing business and ability to pursue other strategic opportunities.

The return structure and risk profile of ADS Contract and any future data center contract will differ from those of NIPSCO's traditionally regulated utility operations.

NIPSCO's and GenCo's operations under the ADS Contract will be, and under future data center contracts are expected to be, regulated by the IURC in a different way from the regulatory mechanisms applicable to NIPSCO's historical operations, which affects the manner in which we recover our investment costs and earn a return on our investment. NIPSCO's electric utility rates historically have been determined and approved in regulatory proceedings with the IURC based on an analysis of NIPSCO's costs to provide utility service and a return on, and recovery of, NIPSCO's investment in the utility business. Through the IURC rate-making process, retail rates may be adjusted over time, and NIPSCO may request additional revenue, in order to cover ongoing costs and investment and earn an adequate return.

In contrast, the terms of the ADS Contract were, and the terms of any future contracts with other data center customers are expected to be, determined through commercial negotiations. In the case of the ADS Contract, these terms include the charges that we receive from ADS, which are designed to allow us to recover the costs that we incur to construct and operate the Contract Assets and earn a return, and provisions that may result in adjustments to those charges such as, among other factors, those relating to certain liquidated damages that we may owe ADS in the event of construction delays or capacity shortfalls and the parties' responsibility to share cost overruns, among other provisions. The terms of any future data center contracts we enter into may differ from the terms of the ADS Contract. For example, customer demand may not be served through designated assets and may contemplate that capacity will be procured via PPAs with third parties. However, the terms of any future data center contracts (including the charges we receive from customers and any potential adjustments to such charges) will inform our ability to recover our investments and earn a return. These terms of the ADS Contract do not, and the terms of any future data center contract are not expected to, guarantee a specific overall rate of return, and the overall return we earn under the ADS Contract or any future data center contracts may ultimately be lower than that of NIPSCO's traditional utility operations. The IURC will not determine the commercial terms of the ADS Contract and is not expected to determine the commercial terms of any future data center contracts; however, the IURC is expected to maintain oversight under the ADS Contract and any future data center contracts to ensure NIPSCO provides reliable service to ADS and any future data center customers at just and reasonable rates. In order to recover our investment costs and earn our return under the ADS Contract and any future data center contracts, our subsidiaries must efficiently perform their own obligations and must look to ADS or future customers (or, if applicable, any parent guarantor) to perform its obligations, rather than the IURC making use of its traditional rate-making process. In addition, under the ADS Contract, NIPSCO has direct contractual obligations to the ADS to, among other things, construct the Contract Assets and deliver committed electric capacity in fixed amounts by certain dates. We expect our subsidiaries to have comparable contractual obligations to customers in connection with any future data center contracts. If disputes arise with data center customers, including ADS, regarding provisions of a data center contract, including the ADS Contract, or payments to be made or actions to be taken thereunder, we may be significantly disadvantaged as a result of, among other factors, the significance of such contracts to us and the greater resources (financial and otherwise) available to the relevant customer. Any dispute or litigation with a data center customer, including ADS, could create significant demands on the attention of management and result in significant costs to us.

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In addition, the IURC, through its review and approval of the ADS Contract and any future data center contracts, and the related PPAs between NIPSCO and GenCo, will have ultimate authority over the implementation of these agreements. In this context, we will need to continuously assess the applicability of ASC Topic 980 over the life of the ADS Contract and other data center contracts. It is possible that significant construction overruns, capacity shortfalls or other events that could result in NIPSCO or GenCo owing liquidated damages under the ADS Contract or any future data center contract could either preclude ongoing application of ASC Topic 980 or result in an immediate disallowance and impairment of the Contract Assets, or, if applicable, and any generation and transmission assets we develop to support future data center contracts. In addition, early termination of the ADS Contract or any future data center contract, as applicable, could result in such impairment and discontinuation of application of ASC Topic 980 with respect to the assets being constructed to serve the applicable data center contract, unless such assets can be used to support new or existing customers. If we incur significant costs that we are not able to recover from ADS or future data center customers (for example, greater than expected purchases of market capacity or operations and maintenance costs significantly exceeding those contemplated by the ADS Contract or any future data center contract), this also could discontinue the application of ASC Topic 980 to the ADS Contract and the Contract Assets, or other applicable data center contract and related assets.

Our partnership with ADS exposes us to significant customer concentration risk.

ADS will be a significant customer of our electric utility operations. For example, the generating capacity of the Contract Assets, when fully delivered into service, is expected to be approximately equivalent to the generating capacity of all NIPSCO's existing generating assets. However, ADS has the right to terminate the ADS Contract for convenience following certain notice periods. If ADS terminates or defaults under the ADS Contract or elects not to renew the ADS Contract after the initial term, we may not be able to replace ADS' demand or otherwise fully utilize the assets constructed in connection with the ADS Contract. We also may not receive the same level of return with respect to any alternative use.

In addition, ADS has a one-time option (exercisable no later than March 31, 2029) to halve committed capacity under the ADS Contract to 1,200 MW commencing January 31, 2032. If ADS elects to reduce the committed capacity under the ADS Contract or to terminate the ADS Contract during its initial term, we will not receive the full earnings we expect to receive over the life of the ADS Contract. Although the ADS Contract provides for reimbursement for our investment in the Contract Assets and related expenses in the event of a reduction in the committed capacity or early termination, the amount of any reimbursement is capped under the ADS Contract, with the amount of the caps being based on cost estimates determined as of signing. Furthermore, our ability to collect any reimbursable amounts will depend upon the willingness and ability of ADS or its parent guarantor to satisfy their payment obligations under the ADS Contract and related guarantee. Accordingly, we may not be able to recover our full investment, which may adversely affect our future results and financial condition.

Any of the above outcomes could adversely affect our future results, financial conditions and results of operations. Termination of the ADS Contract during its initial term or exercise by ADS of its one-time option to reduce capacity also may cause us reputational harm, which could, among other things, negatively affect our ability to source and execute contracts with additional data center customers.

Although we anticipate expanding our base of data center customers, we expect the total number of data center customers we serve to remain relatively small by comparison to our current customer base. Any future data center contracts our subsidiaries enter into may contain termination and/or capacity reduction provisions and related reimbursement comparable to the ADS Contract, exposing us to risks comparable to those described above (the significance of which will be affected by the relative size of any such contract and the costs we incur to develop resources supporting such contract). The concentration of business with a small number of customers in an industry based on emerging technologies, including artificial intelligence and machine learning, presents several risks for us. Our data center customers' technologies and their related business applications have developed rapidly in recent years and continue to develop. We cannot predict the rate at which or the extent to which these emerging technologies will be broadly adopted and successful as business models. Additionally, these customers may experience business downturn, which may cause the loss of these customers or may weaken their financial condition. Similarly, customers may reduce their investment in these new technologies or abandon them entirely.

Many factors, including those outside our and our data center customers' control, could cause our data center customers to terminate their data center contracts or exercise any applicable options to reduce capacity. These factors also could contribute to an overall lessening of demand from data center customers. Such factors include, for example: (i) construction delays, cost overruns or capacity shortfalls that occur in connection with our construction of the generation and transmission assets we plan to construct to serve our data center customers, (ii) similar problems that our data center customers may encounter in

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connection with constructing their data centers, (iii) any decrease or lessening of current cloud-computing or artificial intelligence demand trends or a change in the current supportive legal and regulatory environment (in Northern Indiana or elsewhere) with respect to cloud-computing or artificial intelligence, as well as other factors such as environmental concerns (for example, relating to the sourcing of natural gas to power data centers or supplying water from local resources to cool data centers), which could negatively impact the demand for data centers, (iv) technological or other advances impacting the design and operation of data centers, which could reduce the amount of electricity needed to power data centers, potentially significantly, (v) competing energy technologies could become a preferred source of energy for powering data centers, (vi) any business downturns or weakening financial condition that our data center customers may experience and (vii) any decision by our data center customers to reduce their investment in these new technologies or abandon them entirely.

In addition, as a result of the ADS Contract, and any further agreements we may sign with data center companies, our stock price may experience increased volatility as a result of factors outside our control. For example, our stock price may be negatively affected as a result of any actual or perceived slowdown in the adoption of artificial intelligence technology, the regulation or proposed regulation of such technology, or actual or perceived changes in the strategic or financial position of our data center customers. The trading prices for shares of stock in a number of U.S. public companies operating or serving data centers have recently experienced significant volatility.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We have implemented and maintain a comprehensive cybersecurity program that includes a variety of security controls and measures designed to identify, assess, and manage material cybersecurity risks. The program is a part of our enterprise risk management strategy. The enterprise risk team and the Risk Management Committee review material risks to any NiSource operating company based on perspectives from external experts, peer surveys, and the potential impact to our enterprise assets and strategic objectives.

Risk events are classified based on both the timing of impact and NiSource's ability to preventatively mitigate the risk. For the cybersecurity risks that can be preventively mitigated, the enterprise risk team gathers quarterly updates on mitigation gap closure from risk owners. The Risk Management Committee reviews any mitigation gaps identified by risk owners and approves or rejects the pace of mitigation activities as a statement of risk tolerance and then directs that mitigation activities be included in budgets and the business plan as appropriate.

Our cybersecurity program includes the following key components:

Risk assessment. We regularly assess our cybersecurity risks to identify and prioritize the most significant threats. The risk assessment process considers a variety of factors, including those specific to the utility/energy industry, the types of data we collect and store, and the threats posed by known vulnerabilities. We engage third parties to perform independent assessments of our cybersecurity program, provide intelligence about the threat environment, and to provide operational assistance in managing the program. Annually, a third-party independent assessment is performed to evaluate our cybersecurity maturity against a framework of cybersecurity controls. We also perform bi-annual penetration testing and social engineering assessments performed by a third-party.

Third-party risk management. We perform cyber assessments periodically on all third-party vendors and service providers with whom we share data, rely on for critical business functions, or provide access to our network or systems. Our Supply Chain function works with the Legal and Cyber functions to periodically update cybersecurity contractual provisions in its vendor agreements, with deviations from such provisions requiring approval from the Legal and Cyber functions. Our Supplier Code of Business Conduct requires, among other things, that suppliers ensure safe and secure use of information assets, comply with applicable law relating to personal information, and adhering to standards relative to the use and protection of our information, including that of our employees, customers, vendors and other stakeholders. In addition, all vendors and contractors that have access and/or connectivity to our environment must complete cybersecurity training annually.

Security controls. We have implemented a variety of security controls to mitigate cybersecurity risks. These controls include technical controls, such as firewalls and intrusion detection systems, as well as administrative controls, such as employee training and security awareness programs. To ensure cybersecurity controls, our operational technology within the electric business adheres to the NERC CIP. Within the natural gas business, cybersecurity controls are managed and monitored based on the TSA Security Directives.

Incident response. We have a comprehensive incident response plan in place to respond to cybersecurity incidents. The plan includes steps for detection, analysis, containment, eradication, and recovery from incidents, as well as steps for notifying affected individuals and regulators.

The Audit Committee of our Board has responsibility for oversight of the cybersecurity program and risks from cybersecurity threats. The Audit Committee regularly reviews our cybersecurity posture. The CISO briefs the Audit Committee on cybersecurity risks and risk mitigation initiatives and actions. In addition, the Board remains informed of key and emerging cybersecurity risks and receives updates by the Audit Committee after each of its regularly scheduled meetings.

At the management level, the CISO leads the cybersecurity program and is responsible for assessing and managing cybersecurity risks. Our CISO has expertise and experience in cybersecurity derived from over 15 years of cyber related work experience and possesses several certifications including CISSP, CRISC, and CISA. The CISO is supported by the NiSource Enterprise Security team which performs the cybersecurity function and engages directly on the prevention, detection, mitigation, and remediation of cybersecurity incidents.

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As of the date of filing this Annual Report on Form 10-K, we are not aware of any material cybersecurity incidents during the past year. We monitor the increasing sophistication of cybersecurity threats and continue to allocate resources to enhance our cybersecurity program to protect its information systems and assets. No cybersecurity program is effective to identify and mitigate all threats and we cannot guarantee that we will be able to prevent all cybersecurity incidents. Such an incident could interrupt our normal operations and require us to incur significant costs to remediate any such incident and could have a material impact on our businesses, operations and financial condition. For more information regarding the risks associated with cybersecurity, refer to "Item 1A. Risk Factors" of this Annual Report on Form 10-K.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2025.

Columbia Operations

Refer to Item 1, "Business - Columbia Operations," of this report for further information on Columbia Operations properties.

NIPSCO Operations

Refer to Item 1, "Business - NIPSCO Operations," of this report for further information on NIPSCO Operations properties.

Corporate and Other Operations

We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership

Our principal properties and our subsidiaries' principal properties are free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in the various communities we serve are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties was purchased, a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors' ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

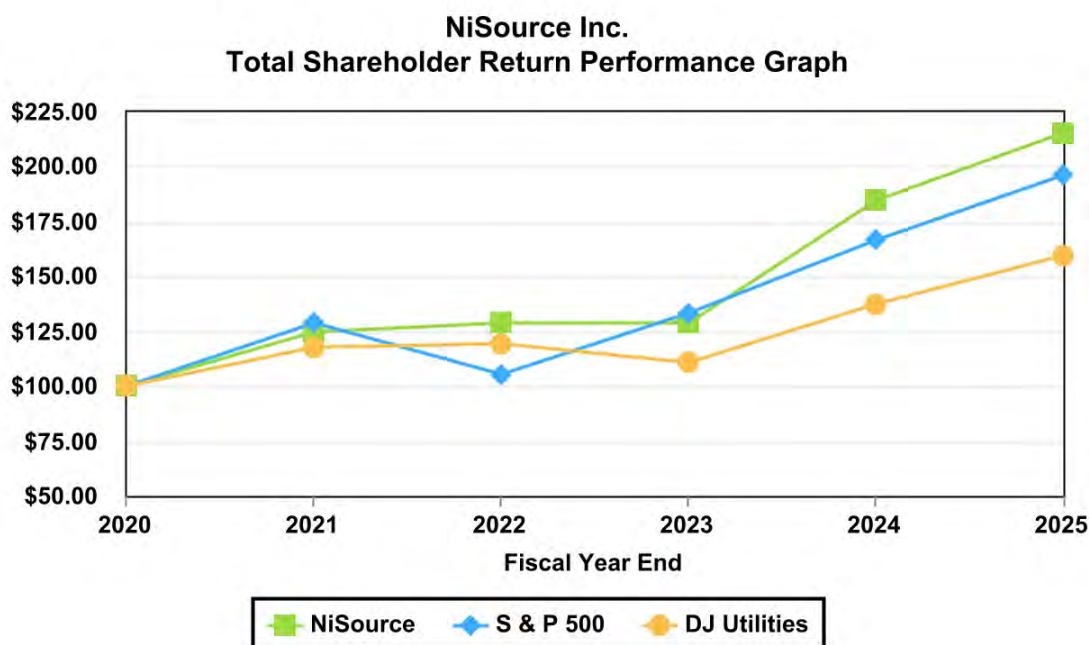
NiSource’s common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource’s common stock are entitled to receive dividends if and when declared by the Board out of funds legally available. There is no preferred stock outstanding as of December 31, 2025. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its January 22, 2026 meeting, the Board declared a quarterly common dividend of \$0.300 per share, payable on February 20, 2026 to holders of record on February 3, 2026.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource’s subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

As of February 4, 2026 NiSource had 14,211 common stockholders of record and 478,533,171 shares outstanding.

The graph below compares the cumulative total shareholder return of NiSource’s common stock for the period commencing December 31, 2020 and ending December 31, 2025 with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices.



The foregoing performance graph is being furnished as part of this Annual Report on Form 10-K solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of \$100 and assumes dividend reinvestment.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. For the three months ended December 31, 2025, no equity securities that are registered by NiSource Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6. RESERVED

Not applicable.

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EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations ("Management's Discussion") includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" and Item 1A, "Risk Factors" at the beginning of this report for a list of factors that may cause results to differ materially. Refer to the "Business" section under Part I, Item 1 of this Annual Report on Form 10-K and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for further discussion of our regulated utility business segments.

This Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. We generate substantially all of our operating income through these rate-regulated businesses, which are summarized for financial reporting purposes into two primary reportable segments: Columbia Operations and NIPSCO Operations.

Our vision is to be a premier, innovative and trusted energy partner. We exist to deliver safe, reliable energy that drives value to our customers. In order to achieve this goal, we seek to develop strategies that benefit all stakeholders as we (i) support long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures and regulatory programs with our cost structure, and (iii) create value and enable growth in an evolving energy ecosystem. These strategies focus on improving safety and reliability, enhancing customer experience, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer value and reducing emissions while generating sustainable returns. The safety of our customers, communities and employees remains our focus. Serving as a guiding practice for our SMS, NiSource is certified in conformance to the American Petroleum Institute Recommended Practice 1173, which is the foundation to our journey towards operational excellence.

2025 Overview:

In 2025, we continued to make significant progress on the remaining portfolio of projects that will enable our electric generation transition, including placing two solar projects and one solar and battery project into service. We advanced our Data Center strategy significantly by creating our GenCo affiliate, whose goal is to build capacity to serve large load customers. We also executed the ADS Contract and related EPC contracts discussed below. During the year, we received orders for four rate cases: Columbia of Maryland, Columbia of Pennsylvania, Columbia of Virginia, and NIPSCO Electric. Between our Columbia and NIPSCO Operating Segments, we added 24,000 customers. We also invested \$1.6 billion in infrastructure modernization to enhance safe, reliable service, including replacement of 256 miles of distribution main and service lines, 45 miles of underground cable and 1,656 electric poles. We concluded the second and third phases of a WAM ERP program, covering all gas distribution operations across our operating territories and our generation assets, to optimize the scheduling, dispatch, and execution of our field operations.

ADS Contract and Data Center Strategy:

ADS Contract

In September 2025, NIPSCO entered into an agreement with ADS, a wholly-owned subsidiary of Amazon.com, Inc., under which NIPSCO will provide electricity to ADS' data centers. Under the ADS Contract, which is pending IURC approval, NIPSCO will provide electric service to ADS pursuant to a capacity commitment beginning in 2027 and increasing annually to

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

2,400 MW by the end of 2032 and will construct up to 3,000 MW of dispatchable generation to provide such electric service. The ADS Contract's initial term ends 15 years after the initial energization of ADS' initial data center. Starting January 2027, ADS will regularly pay NIPSCO a fixed capacity charge and certain pass-through charges. Amazon.com, Inc. a publicly traded, investment-grade parent company has guaranteed ADS' payment obligations. These charges are structured to provide us with a return of our invested capital over the fifteen-year initial term. In addition, the ADS Contract contains provisions for adjustment of the charges designed to provide us with an unlevered internal rate of return on our invested capital over the initial term within a defined range, which we expect over the life of the ADS contract to result in an overall realized return greater than that of NIPSCO's current electric operations, driven by execution and financing. Our realized return may be impacted by factors such as construction costs, operating performance, financing costs and other variables. NIPSCO will also propose to the IURC a mechanism to pass savings back to retail customers for use of the existing system which is expected to begin in 2027. Refer to Part I, Item 1A, "Risk Factors" for a discussion of certain of these factors and other risks relating to the ADS Contract.

In order to meet demand under the ADS Contract, NIPSCO has entered into a PPA with GenCo, which is pending IURC approval and contains terms and provisions substantially similar to the ADS Contract, such that economic benefits (except savings that are expected to be passed to retail customers as described above) and obligations of the ADS Contract as they relate to the Generation Assets (as defined below) are expected to be borne by GenCo and NiSource, as GenCo's ultimate parent company, rather than NIPSCO.

GenCo plans to construct 400 MW of new battery storage and a new power generation facility consisting of two 1,300 MW CCGTs, which are expected to reach commercial operation between 2028 and 2032 (such assets, collectively, the "Generation Assets"). NIPSCO currently has a proceeding before the IURC to approve the generation facilities required to be built for ADS. GenCo has entered into engineering, procurement and construction contracts (the "EPC Contracts"), and certain equipment supply contracts, including a contract to acquire turbines, with respect to the construction of the Generation Assets. The aggregate cost of the Generation Assets, together with the cost to develop related transmission infrastructure (collectively, the "Contract Assets"), is currently estimated to be approximately \$7 billion. The EPC Contracts provide certain protections against cost overruns, and any excess costs with respect to the EPC Contracts beyond those protections, or arising apart from the EPC Contracts are, unless otherwise agreed by the parties, shared by ADS and NIPSCO (for transmission) and GenCo (for generation). If the Contract Assets are delivered into service late or do not achieve certain performance-related milestones, ADS is entitled to liquidated damages, subject to a cap and offset against the regular charges paid by ADS.

Either party may terminate the ADS Contract upon certain defaults or failure to obtain necessary related approvals from the IURC and FERC. ADS may terminate the ADS Contract for convenience following certain notice periods and also has a one-time option (exercisable no later than March 31, 2029) to halve the committed capacity under the ADS Contract to 1,200 MW commencing January 31, 2032. If ADS terminates for convenience, exercises its reduction option or defaults, NIPSCO or its affiliates will be reimbursed for investment costs, subject to agreed caps based on cost estimates by year as of signing. NIPSCO's aggregate liability, including liquidated damages, is subject to a cap.

NIPSCO's and GenCo's operations under the ADS Contract will be regulated by the IURC in a different way from the regulatory mechanisms applicable to NIPSCO's historical operations. The terms of the ADS Contract were determined by commercial negotiation with ADS. These terms include the charges we receive from ADS and provisions that may result in adjustments to such charges, including those relating to certain liquidated damages that we may owe ADS in the event of construction delays or capacity shortfalls, the parties' responsibility to share cost overruns, certain changes in law and force majeure events. The IURC will not determine the commercial terms of the ADS Contract; however, the IURC will maintain oversight under the ADS Contract to ensure NIPSCO provides reliable service to ADS at just and reasonable rates. In order to recover our investment costs and earn our return under the ADS Contract, our subsidiaries must efficiently perform their own obligations and must look to ADS (or its parent guarantor) to perform its obligations, rather than the IURC making use of its traditional rate-making process. In addition, under the ADS Contract, NIPSCO has direct contractual obligations to ADS to, among other things, construct the Contract Assets and deliver required committed electric capacity in fixed amounts by certain dates.

The terms of any future data center contracts we enter into may differ from the terms of the ADS Contract. For example, customer demand may not be served through designated assets and may contemplate that capacity will be procured via PPAs with third parties. However, the terms of any future data center contracts (including the charges we receive from customers and any potential adjustments to such charges) will inform our ability to recover our investments and earn a return. Similar to the ADS Contract, any additional data center contracts will be subject to IURC approval and oversight authority, but the IURC will not determine the commercial terms.

Data Center Strategy

We continue to experience strong demand from potential data center customers in our northern Indiana service territory and are engaged in negotiations with potential counterparties. Through certain of our subsidiaries, we have entered into certain

NISOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

construction and equipment supply contracts in relation to additional generation and transmission assets that may be used to serve potential future data center customers. As we continue to evaluate our potential data center opportunities, we will continue to focus on the community, financial, operational and regulatory factors that must be managed effectively in order to succeed with our data center strategy. We believe data center development can enhance our local tax base, diversify the employment base across the state of Indiana, and provide greater value to existing customers and shareholders. We continually evaluate ways to effectively manage the potential power demand, generation sources, and transmission capabilities to meet potential further load growth from additional data center customers, while at the same time focusing on our environmental goals.

In order to perform under any further data center contracts, we expect that we would need to develop additional generation and transmission assets, which may be significant, and obtain additional financing in connection with such development. For these and other reasons, our ability to successfully execute our data center strategy is subject to a number of risks and uncertainties. Refer to Part I, Item 1A, "Risk Factors" for a discussion of certain risks relating to our data center strategy.

Energy Transition:

We continue to advance our energy transition strategy, primarily through the continuation and enhancement of existing programs, such as implementing our plan to retire and replace remaining coal-fired electric generation by 2028 with a balanced mix of low- or zero-emission electric generation, ongoing pipe replacement and modernization programs, and deployment of advanced leak detection and repair. We continue to make progress on our electric generation transition, initiated through our 2018 Integrated Resource Plan ("2018 Plan"), and we are continually adjusting to the dynamic energy landscape. As of December 31, 2025, we have placed in service owned renewable and storage projects with combined nameplate capacities of 1,950 MW and 101 MW respectively. Renewable PPA projects with a combined nameplate capacity of 1,200 MW have also been placed in service. For additional information, see Note 14, "Other Commitments and Contingencies - D. Other Matters". In December 2025, before the planned retirement of the R.M. Schahfer coal facility, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring R.M. Schahfer to continue operating for 90 days, through March 2026. The order stated that continued operation of R.M. Schahfer was required to meet an energy emergency across MISO's North and Central regions and authorizes NIPSCO to obtain cost recovery pursuant to 16 U.S.C. § 824a(c). For additional information, see "Results and Discussion of Operations - NIPSCO Operations," in this Management's Discussion, and see Part I, Item 1A. "Risk Factors" in this Annual Report on Form 10-K.

NIPSCO's 2021 Plan calls for a new natural gas peaking facility to replace existing vintage gas peaking facilities at the R.M. Schahfer Generating Station to support system reliability and resiliency, and upgrades to the electric transmission system. Following approval by the IURC in October 2024, the construction of a new 400 MW natural gas peaking generation facility is underway, which is expected to support the planned retirement of the existing vintage gas peaking facilities by the end of 2028. The 2021 Plan affirms Michigan City 2028 retirement and calls for new natural gas peaking facilities. Final retirement dates for these units will be subject to MISO approval.

NIPSCO's 2024 Integrated Resource Plan ("2024 Plan") was submitted to the IURC on December 9, 2024. The 2024 Plan maintains the retirement decisions and capacity additions identified in the 2018 and 2021 Integrated Resource Plans and calls for additional generation resources through 2029 to support capacity requirements. The 2024 Plan informs future generation investments required to ensure reliability for NIPSCO's customers and incorporates factors such as anticipated load growth from data centers and other economic development opportunities, EPA emissions rules, and evolving MISO resource accreditation rules. Given that the 90-day 202(c) order could continue to be issued every 90 days to keep Schahfer Units 17 & 18 open for the foreseeable future, and given that MISO's resource accreditations for renewables and storage remain uncertain, it may be necessary to evaluate changes to our previously communicated resource timelines and alternative resource decisions. We plan to move as efficiently as possible while maintaining the integrity of our commercial, planning, regulatory, procurement and operational execution processes.

We continue to enhance safety and reduce methane emissions on our gas systems through modernization programs and utilization of advanced leak detection and repair. In addition, we plan to advance other low- or zero-emission energy resources and technologies, such as hydrogen and renewable natural gas.

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Transformation:

We are modernizing and unlocking efficiencies within our systems and processes on operational excellence, safety, operation and maintenance management. These efforts include investments in proven technologies backed with standardized processes that will change the way we plan, schedule, and execute work in the field and how we engage and provide service to our customers. We delivered the first major milestones of our transformation roadmap through the implementation of phases of our WAM ERP program, foundational AMI capabilities, and completion of certain cyber enhancements to continue to advance the cybersecurity program. Our WAM ERP program has been implemented across our electric and transmission operations, all gas distribution operations and our generation assets. This ERP system standardizes processes around the design and build of our assets as well as optimizes the scheduling, dispatch, and execution of our field operations. We continue to focus on our customer technology platforms. In addition to transforming technology to enhance our employee and customer experiences, we believe these programs will modernize systems and further reduce our enterprise risk related to end-of-life systems.

Economic Environment:

We continue to monitor risks related to order and delivery lead times for construction and other materials, potential unavailability of materials due to global shortages in raw materials, and decreased construction labor productivity in the event of disruptions in the availability of materials. We continue to experience elevated material and supply costs in certain product sourcing categories driven by increased demand and tariffs. To the extent that work plan delays occur or our costs increase, our business operations, results of operations, cash flows, and financial condition could be materially adversely affected. Refer to Part I, Item 1A. Risk Factors, "Financial, Economic and Market Risks" of this Annual Report on Form 10-K for further detail.

We are faced with increased competition for employee and contractor talent in the current labor market which has resulted in increased costs to attract and retain talent. We are ensuring that we use all internal human capital programs (development, leadership enablement programs, succession, performance management) to promote retention of our current employees along with having a competitive and attractive appeal for potential recruits. Our flexible work arrangements, where possible, support a broader talent footprint for sourcing talent needed and for remaining competitive.

We continue to evaluate our financing plan to manage interest expense and exposure to rates. For more information on interest rate risk, see "Market Risk Disclosures" and Part I, Item 1A. Risk Factors, "Financial, Economic and Market Risks" of this Annual Report on Form 10-K.

NIPSCO Minority Interest Transaction:

In December 2023, contemporaneously with the closing of the NIPSCO Minority Interest Transaction, Blackstone, NIPSCO Holdings I, NIPSCO Holdings II, and NiSource entered into an Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II. In January 2024, BIP transferred its equity interest to one of its affiliates and the members of NIPSCO Holdings II entered into a Second Amended and Restated Limited Liability Company Operating Agreement of NIPSCO Holdings II. In October 2025, the members of NIPSCO Holdings II entered into a Third Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II (the "Amended LLC Agreement"), which, among other changes, increased the amount and time period for additional mandatory capital contributions required to be contributed by the members affiliated with Blackstone by \$175 million and seven years, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof, and amended certain provisions to facilitate NIPSCO Holdings II and its subsidiaries' provision of electric service to data center customers (and related activities) and their related contracts and arrangements with Generation Holdings II and its subsidiaries. The members of NIPSCO Holdings II that are affiliates of Blackstone must vote their equity holdings under the Amended LLC Agreement as one investor. Refer to Note 4, "Noncontrolling Interests," in the Notes to the Consolidated Financial Statements for more information on this transaction.

GenCo Minority Equity Interest Transaction:

In October 2025, NiSource issued a 19.9% equity interest in NiSource's wholly-owned subsidiary Generation Holdings II to BIP Orion Holdco L.P. and BIP Orion Holdco II L.P., affiliates of Blackstone (collectively, "Blackstone Investor"), in exchange for \$35.2 million in cash contributions to Generation Holdings II through an Amended and Restated Limited Liability Company Agreement of Generation Holdings II (the Generation Holdings II "LLC Agreement"). Generation Holdings II is the sole owner of GenCo.

The Generation Holdings II LLC Agreement establishes, among other things, governance rights, exit rights, requirements for additional capital contributions, mechanics for distributions, and other arrangements for Generation Holdings II. Specifically,

NISOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

under the terms of the Generation Holdings II LLC Agreement, Blackstone Investor will provide up to \$1.325 billion in additional capital contributions over a seven-year period, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof. Under the Generation Holdings II LLC Agreement, Blackstone Investor is entitled to appoint two directors to the board of directors of Generation Holdings II (the "Holdings II Board") so long as Blackstone Investor (together with any approved affiliate) holds at least a 17.5% Percentage Interest (as defined in the Generation Holdings II LLC Agreement). Blackstone Investor appointed two directors to the Holdings II Board, such that the Holdings II Board is comprised of seven directors, two appointed by Blackstone Investor and five appointed by NiSource. The Generation Holdings II LLC Agreement also contains certain investor protections, including, among other things, requiring Blackstone Investor approval for Generation Holdings II to take certain major actions outside of the normal course of business. In addition, the Generation Holdings II LLC Agreement contains certain terms surrounding transfer rights and other obligations applicable to both Blackstone Investor and NiSource. Under the Generation Holdings II LLC Agreement, Generation Holdings II has agreed that, so long as Blackstone Investor holds a 14.9% or greater percentage interest in Generation Holdings II, Generation Holdings II, NIPSCO Holdings II (as defined below) and/or their respective subsidiaries will be the exclusive vehicles for all power, storage and generation requirements for data center customers within NIPSCO's service territory. The Generation Holdings II LLC Agreement also establishes that NiSource will be attributed 80.1% of any profit or loss from Generation Holdings II, through its wholly owned subsidiary GenCo, with the Blackstone Investor being attributed the remaining 19.9% of any profit or loss.

NiSOURCE INC.**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)****Summary of Consolidated Financial Results**

A summary of our consolidated financial results for the years ended December 31, 2025, 2024 and 2023, are presented below:

Year Ended December 31, (in millions, except per share amounts)	2025	2024	2023	Favorable (Unfavorable)	
				2025 vs. 2024	2024 vs. 2023
Operating Revenues	\$ 6,642.2	\$ 5,455.1	\$ 5,505.4	\$ 1,187.1	\$ (50.3)
Operating Expenses					
Cost of energy	1,584.4	1,132.2	1,533.3	(452.2)	401.1
Other Operating Expenses	3,222.5	2,867.4	2,676.6	(355.1)	(190.8)
Total Operating Expenses	4,806.9	3,999.6	4,209.9	(807.3)	210.3
Operating Income	1,835.3	1,455.5	1,295.5	379.8	160.0
Total Other Deductions, Net	(618.9)	(452.7)	(481.6)	(166.2)	28.9
Income Taxes	203.8	158.1	139.5	(45.7)	(18.6)
Net Income	1,012.6	844.7	674.4	167.9	170.3
Net (loss) income attributable to noncontrolling interest	83.1	84.3	(39.9)	1.2	(124.2)
Net Income attributable to NiSource	929.5	760.4	714.3	169.1	46.1
Preferred dividends and redemption premium	—	(20.7)	(52.6)	20.7	31.9
Net Income Available to Common Shareholders	929.5	739.7	661.7	189.8	78.0
Basic Earnings Per Share	\$ 1.96	\$ 1.63	\$ 1.59	\$ 0.33	\$ 0.04
Diluted Earnings Per Share	\$ 1.95	\$ 1.62	\$ 1.48	\$ 0.33	\$ 0.14

The majority of the costs of energy in both segments are tracked costs that are passed through directly to the customer, resulting in an equal and offsetting amount reflected in operating revenues.

The increase in net income available to common shareholders during 2025 was primarily due to higher revenues, net of cost of energy, driven by our continued investment in safety and successful regulatory outcomes for these investments, reliability and low- or zero-emission generation year-over-year. The increase in net income available to common shareholders is partially offset by higher operation and maintenance expense, higher depreciation expense attributed to our planned capital expenditures, and increased interest expense.

For additional information on operating income variance drivers see "Results and Discussion of Operations" for Columbia Operations and NIPSCO Operations in this Management's Discussion.

Other Deductions, Net

The change in Other deductions, net in 2025 compared to 2024 is primarily driven by higher long-term debt interest in 2025 and lower AFUDC in 2025 driven by lower CWIP outstanding year-over-year. See Note 7, "Short-Term Borrowings," Note 8, "Long-Term Debt," Note 22, "Other, Net," and Note 23, "Interest Expense, Net," in the Notes to Consolidated Financial Statements for additional information.

Income Taxes

The increase in income tax expense in 2025 compared to the same period in 2024 is primarily due to higher pre-tax income, partially offset by the tax effect of non-controlling interest. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

RESULTS AND DISCUSSION OF OPERATIONS

Presentation of Segment Information

Columbia Operations aggregates the results of the fully regulated and wholly owned subsidiaries of NiSource Gas Distribution Group, Inc. Each Columbia distribution company is an operating segment which we aggregate to form the Columbia Operations reportable segment. NIPSCO Operations aggregates the results of NIPSCO Holdings I, and its majority-owned subsidiaries, including NIPSCO, which has both regulated gas and electric operations in northern Indiana. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as a reportable segment, are presented as "Corporate and Other" within the Notes to the Condensed Consolidated Financial Statements (unaudited) and primarily are comprised of interest expense on holding company debt, unallocated corporate costs and activities and new business development costs associated with GenCo.

NiSOURCE INC.
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)
Columbia Operations

Financial and operational data for the Columbia Operations segment for the years ended December 31, 2025, 2024 and 2023, are presented below:

Year Ended December 31, (in millions)	2025	2024	2023	Favorable (Unfavorable)	
				2025 vs. 2024	2024 vs. 2023
Operating Revenues	\$ 3,343.3	\$ 2,716.0	\$ 2,746.1	\$ 627.3	\$ (30.1)
Operating Expenses					
Cost of energy	819.8	514.7	645.0	(305.1)	130.3
Operation and maintenance	923.7	837.5	792.3	(86.2)	(45.2)
Depreciation and amortization	451.2	409.1	371.7	(42.1)	(37.4)
Loss on impairment of assets	—	2.7	—	2.7	(2.7)
Loss on sale of assets, net	0.3	4.7	—	4.4	(4.7)
Other taxes	253.2	218.6	198.8	(34.6)	(19.8)
Total Operating Expenses	2,448.2	1,987.3	2,007.8	(460.9)	20.5
Operating Income	\$ 895.1	\$ 728.7	\$ 738.3	\$ 166.4	\$ (9.6)
Revenues					
Residential	\$ 2,284.0	\$ 1,891.5	\$ 1,882.8	\$ 392.5	\$ 8.7
Commercial	768.0	588.4	606.2	179.6	(17.8)
Industrial	168.8	145.2	139.5	23.6	5.7
Off-System	75.8	42.6	60.7	33.2	(18.1)
Other	46.7	48.3	56.9	(1.6)	(8.6)
Total	\$ 3,343.3	\$ 2,716.0	\$ 2,746.1	\$ 627.3	\$ (30.1)
Sales and Transportation (MMDth)					
Residential	180.3	153.2	155.2	27.1	(2.0)
Commercial	138.3	121.8	120.4	16.5	1.4
Industrial	278.1	277.9	255.3	0.2	22.6
Off-System	26.1	23.8	31.8	2.3	(8.0)
Other	0.3	0.2	0.3	0.1	(0.1)
Total	623.1	576.9	563.0	46.2	13.9
Heating Degree Days⁽¹⁾	5,170	4,262	4,373	908	(111)
Normal Heating Degree Days⁽¹⁾	5,012	5,134	5,137	(122)	(3)
% (Warmer) Colder than Normal	3 %	(17)%	(15)%		
% (Warmer) Colder than Prior Year	21 %	(3)%	(16)%		
Gas Distribution Customers					
Residential	2,237,810	2,225,564	2,215,293	12,246	10,271
Commercial	189,792	188,699	188,561	1,093	138
Industrial	1,988	1,991	1,986	(3)	5
Other	5	5	4	—	1
Total	2,429,595	2,416,259	2,405,844	13,336	10,415

⁽¹⁾ Heating degree figures represent averages of the five jurisdictions served by Columbia Operations.

NISOURCE INC.**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)****Columbia Operations (continued)**

Comparability of operation and maintenance expenses, depreciation and amortization, and other taxes may be impacted by regulatory, depreciation and tax trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2025 to 2024 are presented in the respective tables below.

	Favorable (Unfavorable)	
	2025 vs 2024	
Changes in Operating Revenues (in millions)		
New rates from base rate proceedings and regulatory capital programs	\$	178.9
The effects of weather in 2025 compared to 2024		53.9
The effects of customer growth		5.8
The effects of customer usage		(7.5)
Other		1.4
Change in operating revenues (before cost of energy and other tracked items)	\$	232.5
Operating revenues offset in operating expense		
Higher cost of energy billed to customers		305.2
Higher tracker recoveries within operation and maintenance, depreciation, and tax		89.6
Total change in operating revenues	\$	627.3

Weather

In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days, net of weather and revenue normalization mechanisms. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Columbia Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

Throughput

The increase in total volumes sold and transported in 2025 compared to 2024 of 46.2 MMDth is primarily attributable to the effects of colder weather.

NI SOURCE INC.**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)****Columbia Operations (continued)**Commodity Price Impact

Cost of energy for the Columbia Operations segment is principally comprised of the cost of natural gas procured on behalf of and sold to customers while providing transportation services. All of our Columbia Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. These are tracked costs that are passed through directly to the customer, and the gas costs included in revenues are matched with the gas cost expense recorded in the period. Any difference in actual costs incurred and amounts billed to customers is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income. Certain Columbia Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions.

	Favorable (Unfavorable)
	2025 vs 2024
Changes in Operating Expenses (in millions)	
Higher depreciation and amortization expense	\$ (42.1)
Higher property tax	(18.0)
Higher employee related expenses	(16.0)
Loss on sale of assets and impairments in 2024	7.4
Other	2.6
Change in operating expenses (before cost of energy and other tracked items)	\$ (66.1)
Operating expenses offset in operating revenue	
Higher cost of energy billed to customers	(305.2)
Higher tracker recoveries within operation and maintenance, depreciation, and tax	(89.6)
Total change in operating expense	\$ (460.9)

NI SOURCE INC.
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)
NIPSCO Operations

Financial and operational data for the NIPSCO Operations segment, which services both gas and electric customers, for the years ended December 31, 2025, 2024 and 2023, are presented below:

Year Ended December 31, (in millions)	2025	2024	2023	Favorable (Unfavorable)	
				2025 vs. 2024	2024 vs. 2023
NIPSCO Operations					
Operating Revenues	\$ 3,308.5	\$ 2,752.0	\$ 2,771.6	\$ 556.5	\$ (19.6)
Operating Expenses					
Cost of energy	764.7	617.5	888.3	(147.2)	270.8
Operation and maintenance	848.9	761.4	787.7	(87.5)	26.3
Depreciation and amortization	680.6	590.3	493.8	(90.3)	(96.5)
Loss on impairment of assets	0.7	0.4	—	(0.3)	(0.4)
Loss (gain) on sale of assets, net	—	(1.7)	2.2	(1.7)	3.9
Other taxes	75.5	64.3	57.9	(11.2)	(6.4)
Total Operating Expenses	2,370.4	2,032.2	2,229.9	(338.2)	197.7
Operating Income	\$ 938.1	\$ 719.8	\$ 541.7	\$ 218.3	\$ 178.1

Year Ended December 31, (in millions)	2025	2024	2023	Favorable (Unfavorable)	
				2025 vs. 2024	2024 vs. 2023
NIPSCO Electric					
Revenues					
Residential	\$ 771.4	\$ 649.9	\$ 583.9	\$ 121.5	\$ 66.0
Commercial	716.8	620.4	578.1	96.4	42.3
Industrial	581.3	500.0	475.0	81.3	25.0
Wholesale and Other	139.4	143.3	148.0	(3.9)	(4.7)
Total	\$ 2,208.9	\$ 1,913.6	\$ 1,785.0	\$ 295.3	\$ 128.6
Sales (GWh)					
Residential	3,498.9	3,404.9	3,262.9	94.0	142.0
Commercial	3,737.0	3,697.9	3,614.2	39.1	83.7
Industrial	8,344.8	7,984.8	7,820.3	360.0	164.5
Wholesale and Other	958.1	974.9	635.3	(16.8)	339.6
Total	16,538.8	16,062.5	15,332.7	476.3	729.8
Cooling Degree Days	973	903	710	70	193
Normal Cooling Degree Days	868	852	831	16	21
% Warmer (Colder) than Normal	12 %	6 %	(15)%		
% Warmer (Colder) than prior year	8 %	27 %	(25)%		
NIPSCO Electric Customers					
Residential	433,889	430,648	427,217	3,241	3,431
Commercial	59,831	59,214	58,779	617	435
Industrial	2,109	2,121	2,126	(12)	(5)
Wholesale and other	705	707	711	(2)	(4)
Total	496,534	492,690	488,833	3,844	3,857

NI SOURCE INC.
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)
NIPSCO Operations

Year Ended December 31, (in millions)	2025	2024	2023	Favorable (Unfavorable)	
				2025 vs. 2024	2024 vs. 2023
NIPSCO Gas					
Revenues					
Residential	\$ 712.3	\$ 540.9	\$ 634.9	\$ 171.4	\$ (94.0)
Commercial	271.6	202.4	249.1	69.2	(46.7)
Industrial	100.2	79.0	86.9	21.2	(7.9)
Other	15.5	16.1	15.7	(0.6)	0.4
Total	\$ 1,099.6	\$ 838.4	\$ 986.6	\$ 261.2	\$ (148.2)
Sales and Transportation Volumes (MMDth)					
Residential	66.6	58.2	60.3	8.4	(2.1)
Commercial	47.3	42.5	43.9	4.8	(1.4)
Industrial	267.0	256.8	261.8	10.2	(5.0)
Total	380.9	357.5	366.0	23.4	(8.5)
Heating Degree Days	5,936	4,975	5,198	961	(223)
Normal Heating Degree Days	5,911	6,001	5,954	(90)	47
% Warmer than Normal	— %	(17)%	(13)%		
% (Warmer) Colder than prior year	19 %	(4)%	(15)%		
NIPSCO Gas Customers					
Residential	808,241	801,740	795,656	6,501	6,084
Commercial	66,957	66,633	66,305	324	328
Industrial	2,677	2,734	2,808	(57)	(74)
Total	877,875	871,107	864,769	6,768	6,338

NiSOURCE INC.**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)****NIPSCO Operations (continued)**

Comparability of operation and maintenance expenses and depreciation and amortization may be impacted by regulatory and depreciation trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2025 to 2024 are presented in the respective tables below.

Changes in Operating Revenues (in millions)	Favorable (Unfavorable)	
	2025 vs 2024	
New rates from base rate proceedings and regulatory capital and DSM programs	\$	324.2
The effects of weather in 2025 compared to 2024		48.9
The effects of customer growth		12.8
Renewable Joint Venture revenue, fully offset by Joint Venture operating expense and noncontrolling interest net income (loss)		(8.6)
The effects of customer usage		(3.2)
Other		(3.8)
Change in operating revenues (before cost of energy and other tracked items)	\$	370.3
Operating revenues offset in operating expense		
Higher cost of energy billed to customers		147.0
Lower tracker deferrals within operation and maintenance, depreciation and tax		40.1
Reduction in gross receipts tax, offset in operating expenses		(0.9)
Total change in operating revenues	\$	556.5

Weather

The results of operations for the NIPSCO Operations segment include income from both electric and gas service lines. In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal cooling degree days and normal heating degree days, net of NIPSCO Gas' weather normalization mechanisms. Our composite cooling and heating degree days reported do not directly correlate to the weather-related dollar impact on the results of NIPSCO Operations. Cooling and heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite cooling and heating degree day comparison.

Sales

The increase in total volumes sold to electric customers for twelve months ended December 31, 2025 compared to the same period in 2024 was primarily attributable to residential customer growth and increased usage by commercial customers, partially offset by a decrease in usage by industrial customers. NIPSCO Electric results remains closely linked to the performance of the steel industry. MWh sales to steel-related industries accounted for approximately 49.3% and 49.4% of the total industrial MWh sales for the years ended December 31, 2025 and 2024, respectively.

The increase in total volumes sold to gas customers for the twelve months ended December 31, 2025 compared to the same period in 2024 was primarily attributable to colder weather, as well as residential and commercial customer count growth.

Commodity Price Impact

Cost of energy for the NIPSCO Operations segment's electric activities is principally comprised of the cost of coal, natural gas purchased for internal generation of electricity, transportation of coal and natural gas, and the cost of power purchased from generators of electricity for its generation and transmission activities. For its gas distribution activities, NIPSCO Operations' cost of energy is principally comprised of the cost of natural gas procured on behalf of and sold to customers while providing transportation and distribution services. NIPSCO Operations has state-approved recovery mechanisms that provides a means for full recovery of prudently incurred costs of energy. The majority of these costs of energy are passed through directly to the customer, and the costs of energy included in operating revenues are matched with the cost of energy expense recorded in the

NiSOURCE INC.**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)****NIPSCO Operations (continued)**

period. Any difference in actual costs incurred and amounts billed to customers is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered fuel and gas cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

The underlying reasons for changes in our operating expenses for the twelve months ended December 31, 2025 compared to the same period in 2024 are presented below.

Changes in Operating Expenses (in millions)	Favorable (Unfavorable)	
	2025 vs 2024	
Higher depreciation and amortization expense	\$	(91.2)
Higher outside services expenses		(21.1)
Higher expenses related to uncollectible customer accounts		(11.9)
Higher property tax		(11.4)
Renewable Joint Venture operating expense, partially offset by Joint Venture operating revenues		(8.6)
Higher employee and administrative expenses		(6.6)
Lower environmental remediation costs		5.0
Other		(6.2)
Change in operating expenses (before cost of energy and other tracked items)	\$	(152.0)
Operating expenses offset in operating revenue		
Higher cost of energy billed to customers		(147.0)
Higher tracker deferrals within operation and maintenance, depreciation and tax		(40.1)
Reduction in gross receipts tax, offset in operating revenues		0.9
Total change in operating expense	\$	(338.2)

Electric Supply and Generation Transition

NIPSCO continues to execute on an electric generation transition consistent with the 2018 Plan and 2021 Plan and maintained in the 2024 Plan. See "Liquidity and Capital Resources" in this Management's Discussion for additional information on our capital investment spend. NIPSCO is responding to federal and state executive orders, or other regulatory actions, with respect to its generation transition plans. In December 2025, before the planned retirement of the R.M. Schahfer coal facility, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring R.M. Schahfer to continue operating for 90 days, through March 23, 2026. The order stated that continued operation of R.M. Schahfer was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and the U.S. Department of Energy regulations, the order authorizes NIPSCO to obtain cost recovery pursuant to 16 U.S.C. § 824a(c). As directed, NIPSCO continued to make R.M. Schahfer available in the MISO market. Following receipt of the emergency order, NIPSCO filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. NIPSCO made two filings with the IURC related to the emergency order. The first filing is to confirm accounting treatment of current electric rate order, and the second is a filing for recovery of federally mandated expenses related to the emergency order, which will be utilized in the event that any costs of complying with the emergency order fall outside of the MISO Tariff recovery. For additional information, see Note 12, "Regulatory Matters,".

Since 2020, five PPA projects (three wind and two solar) and eight owned projects (two wind, four solar and two solar plus storage) have been placed into service totaling approximately 3,246 MW of nameplate capacity, including Dunn's Bridge II, Fairbanks, Gibson, Appleseed, and Carpenter, which were placed into service in January, May, August, and December 2025, respectively. NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy has an associated nameplate capacity, and payments under the PPAs do not begin until the associated generation facility is placed into service. We expect the Templeton project, a wind BTA project with a nameplate capacity of 200 MW, to be placed in service in 2027. See "Executive Summary - Energy Transition" in this Management's Discussion for additional information. NIPSCO has sold, and may in the future sell, renewable energy credits from its renewable generation to third parties to offset customer costs.

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Liquidity and Capital Resources

We continually evaluate the availability of adequate financing to fund our ongoing business operations, working capital and core safety and infrastructure investment programs. Our financing is sourced through cash flow from operations, the issuance of debt and/or equity, and minority interest investments in NIPSCO Holdings II and Generation Holdings II. Equity issuances are primarily conducted through our ATM program. Additionally, we received proceeds from tax credit transfers associated with the monetization of credits of \$22.4 million and \$23.5 million for the years ended December 31, 2025 and 2024, respectively. External debt financing is provided primarily through the issuance of long-term debt, accounts receivable securitization programs and our \$1.85 billion commercial paper program, which is backstopped by our committed revolving credit facility. In December 2025, we increased our revolving credit facility availability from \$1.85 billion to \$2.50 billion from third-party lenders. We believe these sources provide adequate capital to fund our operating activities and capital expenditures in 2026 and beyond.

As discussed above under "ADS Contract and Strategy," the aggregate cost of the Contract Assets is currently estimated to be approximately \$7 billion. We expect to finance the construction and development of these assets through a number of sources including but not limited to funds received under the ADS Contract, debt and equity financing raised by NiSource and capital contributions from affiliates of Blackstone to NIPSCO Holdings II and Generation Holdings II in connection with such Blackstone affiliates' minority interest investments in those entities. For additional information on these minority interest investments, refer to Note 4, "Noncontrolling Interests," and Note 19, "Other Commitments and Contingencies - E. Other Matters," included herein. If we enter into additional data center contracts, we expect that we would need to develop additional generation assets to serve our new data center customers. In order to fund the development of these assets which may be significant, we would be required to obtain significant additional financing, for which we may consider other funding sources, structures, or partnerships such as JVs or off-balance sheet arrangements in the form of BTAs to support maintenance of our investment grade credit ratings.

Sources of financing activities for the current year are as follows:

Details of our 2024 ATM program activity are summarized below:

- In February 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,000,000 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$40.10 per share. In September 2025, we settled the forward sale agreement in shares for \$80.0 million, based on a net price of \$40.02 per share.
- In March 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 1,707,320 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$41.00 per share. In September 2025, we settled the forward sale agreement in shares for \$69.9 million, based on a net price of \$40.92 per share.
- In June 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,518,393 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$39.71 per share. In September 2025, we settled the forward sale agreement in shares for \$99.1 million, based on a net price of \$39.36 per share.
- In October 2025, with the commencement of our 2025 ATM program discussed below, we terminated the equity distribution agreements entered into in February 2024 in connection with the 2024 ATM program.

Details of our 2025 ATM program activity are summarized below:

- In October 2025, we entered into eleven separate equity distribution agreements providing for the sale of up to an aggregate of \$1.5 billion of our common stock.

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

- In October 2025, we executed a direct sale agreement of 1,195,029 shares at a price of \$41.84 resulting in net proceeds of \$49.6 million received in November 2025.
- In October 2025, we executed a forward sale agreement, which allows us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,390,057 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$41.84 per share. We may settle the forward sale agreement in shares, cash or net shares by October 2026. Had we settled all of the shares under the forward sale agreement at December 31, 2025, we would have received approximately \$99.7 million, based on a net price of \$41.73 per share.
- As of December 31, 2025 the 2025 ATM program inclusive of the forward sale agreement had approximately \$1.35 billion of equity capacity available. The 2025 ATM program expires in December 2028.

Details of our 2025 long-term debt activity are summarized below:

- In March 2025, we completed the issuance and sale of \$750.0 million of 5.850% senior unsecured notes maturing in 2055, which resulted in approximately \$739.6 million of net proceeds after discount and debt issuance costs.
- In June 2025, we completed the issuance and sale of an additional \$750.0 million of 5.850% senior unsecured notes maturing in 2055 (the "2055 Notes"). The terms of the 2055 Notes, other than the issue date and the price to the public, are identical to the terms of, and constitute a reopening of, our 5.850% senior unsecured notes maturing in 2055 issued in March 2025. With the incremental issuance, we now have \$1.5 billion of 5.850% senior unsecured notes maturing in 2055. In June 2025, we also completed the issuance and sale of \$900.0 million of 5.350% senior unsecured notes maturing in 2035 (the "2035 Notes"). These issuances of the 2055 Notes and the 2035 Notes resulted in approximately \$1.616 billion of total net proceeds after discount and debt issuance costs.
- In August 2025, we repaid \$1,250.0 million of 0.95% senior unsecured notes at maturity.
- In November 2025, we completed the issuance and sale of \$1.0 billion of 5.750% fixed-to-fixed reset rate junior subordinated notes maturing in 2056, which resulted in approximately \$984.3 million of net proceeds after debt issuance costs.
- In December 2025, Columbia of Massachusetts repaid \$10.0 million of 6.430% medium term notes at maturity.

See Note 4, "Noncontrolling Interests," Note 6, "Equity," Note 7, "Short-Term Borrowings," and Note 8, "Long-Term Debt," in the Notes to the Consolidated Financial Statements for more information.

Operating Activities

Net cash from operating activities for the year ended December 31, 2025 was \$2,362.3 million, an increase of \$580.8 million from 2024. This increase in cash from operating activities was primarily attributable to higher net income, depreciation expense, deferred taxes, supplier refunds received in 2025 and decreases in current year exchange gas receivables in 2025 compared to 2024.

Investing Activities

Net cash used for investing activities for the year ended December 31, 2025 was \$4,524.1 million, an increase of \$1,311.1 million from 2024. The year over year increase in investing activities was primarily comprised of milestone payments to renewable generation asset developers for certain of our BTA projects, advanced deposits, and additional capital expenditures in 2025 compared to 2024.

NI SOURCE INC.
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Capital Expenditures. The table below reflects actual capital expenditures and certain other investing activities by segment for 2025.

<i>(in millions)</i>	Actual 2025
Columbia Operations	
System Growth and Tracker	\$ 825.5
Maintenance	387.5
Total Columbia Operations	1,213.0
NIPSCO Operations	
System Growth and Tracker	740.9
Maintenance	596.8
Generation Transition Investments	1,171.2
Total NIPSCO Operations	2,508.9
Corporate and Other Operations ⁽¹⁾	329.7
Total Capital Expenditures⁽²⁾	\$ 4,051.6

⁽¹⁾Certain amounts may subsequently be allocated out of Corporate and Other Maintenance Costs to the Columbia Operations and NIPSCO Operations segments when placed in service. This amount also includes \$39.7 million related to data center generation assets.

⁽²⁾Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.

In addition to these capital expenditures, we invested \$70.5 million in cloud computing costs in 2025. We also made \$373.8 million in advanced deposits for project costs to secure certain long lead equipment related to data center generation assets.

We expect to make capital investments totaling approximately \$21.0 billion during the 2026-2030 period to support our base business (exclusive of investments relating to the ADS Contract), including capital investments to support our generation transition strategy, and to invest approximately \$7.0 billion during that period to develop the Contract Assets in connection with the ADS Contract, as set forth in the table below. As discussed above, if we enter into additional data center contracts, we expect to make significant further capital investments in addition to those set forth in the table below, and/or to consider alternative financing structures such as JVs or off-balance sheet arrangements. The forecasted capital investments are subject to continuing review and adjustment. Actual capital investments may vary from these estimates.

<i>(in billions)</i>	2025 Actual	2026 Estimated	2027 Estimated	2028 Estimated	2029 Estimated	2030 Estimated
Capital Investments (Base Business)	\$4.1	\$3.9 - 4.1	\$3.7 - 3.9	\$3.7 - 3.9	\$4.9 - 5.1	\$4.3 - 4.5
Capital Investments (Data Center Contracts)	0.4	1.2 - 1.4	1.5 - 1.7	1.8 - 2.0	1.0 - 1.2	0.4 - 0.6
Capital Investments (Total)	\$4.5	\$5.1 - 5.5	\$5.2 - 5.6	\$5.5 - 5.9	\$5.9 - 6.3	\$4.7 - 5.1

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Regulatory Capital Programs. We continue to upgrade and modernize our electric system to enhance safety and reliability by addressing aged infrastructure and deploying advanced grid technologies. We are also upgrading and modernizing our gas infrastructure to enhance safety and reliability by reducing leaks. An ancillary benefit of these programs is the reduction of GHG emissions. In 2025, we continued to move forward on core infrastructure investment programs supported by complementary regulatory and customer initiatives across five states of our operating area.

The following table describes the most recent vintage of our regulatory programs to recover infrastructure replacement and other federally mandated compliance investments:

(in millions)

Company	Program	Capital Investment	Investment Period	Filing Date	Costs Covered ⁽¹⁾
Approved					
Columbia of Ohio	IRP - 2025	\$ 978.7	4/21-12/24	2/27/2025	Replacement of hazardous service lines, cast iron, wrought iron, uncoated steel, and bare steel pipe.
Columbia of Ohio	PHMSA IRP - 2025	\$ 78.2	1/23-12/24	2/28/2025	Investments necessary to comply with the PHMSA Mega Rule.
Columbia of Ohio	CEP - 2025	\$ 1,027.8	4/21-12/24	2/27/2025	Assets not included in the IRP or PHMSA IRP.
Columbia of Virginia	SAVE - 2026	\$ 176.1	10/24-12/26	8/12/2025	Replacement projects that (i) enhance system safety or reliability, or (ii) reduce, or potentially reduce, greenhouse gas emissions. Includes costs associated with Advanced Leak Detection and Repair.
Columbia of Kentucky	SMRP - 2026	\$ 181.4	1/23-12/26	10/15/2025	Replacement of mains and inclusion of system safety investments.
NIPSCO - Electric ⁽²⁾	TDSIC - 7	\$ 315.6	7/22-3/25	5/27/2025	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.
NIPSCO - Electric ⁽³⁾	GCT - 2	\$ 229.5	9/23/4/26	6/18/2025	New gas peaker generation project costs forecasted through April 2026.
NIPSCO - Gas	TDSIC - 9	\$ 34.0	3/24-3/25	5/23/2025	New or replacement projects undertaken for the purpose of safety, reliability, system modernization, or economic development.
NIPSCO - Gas	FMCA - 5	\$ 21.9	6/24-6/25	8/27/2025	Project costs to comply with federal mandates.
Pending Commission Approval					
NIPSCO - Gas	TDSIC - 10	\$ 90.3	4/25-9/25	11/25/2025	New or replacement projects undertaken for the purpose of safety, reliability, system modernization, or economic development.
NIPSCO - Electric ⁽³⁾	GCT - 3	\$ 385.6	9/23-10/26	12/16/2025	New gas peaker generation project cost forecasted through October 2026.

⁽¹⁾Programs do not include any costs already included in base rates.

⁽²⁾TDSIC – 7 was originally filed in May 2025 and refiled in July 2025, due to the electric rate case order. The refiled adjusted the capital in the tracker from \$744.7 million to \$315.6 million.

⁽³⁾Capital investment is based on a projected amount. The capital investment has not all been incurred to date and represents a forecasted average for the billing period.

Columbia of Ohio filed an application in December 2025. The application seeks to continue Columbia of Ohio's PHMSA IRP Rider for calendar year 2027. The request includes recovery of \$404.3 million of capital to reconfirm maximum allowable operating pressure of transmission class pipe to meet federal rule requirements.

NIPSCO filed a Gas TDSIC Plan (2026 - 2030) in December 2025. The petition is seeking recovery of new or replacement projects undertaken for the purpose of safety, reliability, system modernization, or economic development. The request includes \$764.7 million of estimated capital, including indirect costs and AFUDC.

Refer to Note 12, "Regulatory Matters," in the Notes to Consolidated Financial Statements for a further discussion of regulatory developments during 2025.

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Financing Activities

Common Stock, Preferred Stock and Equity Unit Sale. Refer to Note 6, "Equity," in the Notes to Consolidated Financial Statements for information on common stock, preferred stock and equity units activity.

Short-term Debt. Refer to Note 7, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 8, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Non-controlling Interest. Refer to Note 4, "Noncontrolling Interests," in the Notes to Consolidated Financial Statements for more information.

Sources of Liquidity

The following table displays our liquidity position as of December 31, 2025 and 2024:

Year Ended December 31, (in millions)	2025		2024	
Current Liquidity				
Revolving Credit Facility	\$	2,500.0	\$	1,850.0
Accounts Receivable Programs ⁽¹⁾		175.0		175.0
<i>Less:</i>				
Commercial Paper		736.0		604.6
Letters of Credit Outstanding Under Credit Facility		25.0		9.4
<i>Add:</i>				
Cash and Cash Equivalents		110.1		156.6
Net Available Liquidity	\$	2,024.1	\$	1,567.6

⁽¹⁾Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2025, the ratio was 51.0%.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and NIPSCO's credit ratings and ratings outlook as of December 31, 2025.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Stable	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Stable	Baa1	Stable	BBB	Stable
Commercial Paper	A-2	Stable	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2025, a collateral requirement of approximately \$150.2 million would be required in the event of a downgrade below investment grade. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Equity. Our authorized capital stock consists of 770,000,000 shares, \$0.01 par value, of which 750,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2025, 478,432,058 shares of common stock were outstanding and no shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 6, "Equity," in the Notes to Consolidated Financial Statements.

Contractual Obligations, Cash Requirements and Off-Balance Sheet Arrangements

We have certain contractual obligations requiring payments at specified periods. Our material cash requirements are detailed below. We intend to use funds from the liquidity sources referenced above to meet these cash requirements.

At December 31, 2025, we had \$15,477.5 million in long-term debt, of which \$19.7 million is current, and \$736.0 million in short-term borrowings outstanding.

During 2026 and 2027, we expect to make cash payments of \$809.5 million and \$879.3 million, respectively, related to pipeline service obligations including demand for gas transportation, gas storage and gas purchases, and \$87.6 million and \$10.4 million, respectively, for long lead time items related to plant equipment purchases.

Our expected payments include employer contributions to pension and other postretirement benefits plans expected to be made in 2026. Plan contributions beyond 2026 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2026, we expect to make contributions of approximately \$2.7 million to our pension plans and approximately \$18.3 million to our postretirement medical and life plans. Refer to Note 16, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to asset retirement obligations on the Consolidated Balance Sheets.

We have uncertain income tax positions for which we are unable to predict when the matters will be resolved. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for more information.

NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," and Note 19, "Other Commitments and Contingencies - E. Other Matters," in the Notes to Consolidated Financial Statements for additional information.

In addition, we, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information regarding our contractual obligations over the next 5 years and thereafter and our off-balance sheet arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. We manage risk through a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk

Our gas and electric subsidiaries have commodity price risk primarily related to the purchases of natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited and does not bear significant exposure to earnings risk, since our current regulatory mechanisms allow recovery of prudently incurred purchased

NISOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. These changes are included in the GCA and FAC regulatory rate-recovery mechanisms. If these mechanisms were to be adjusted or eliminated, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk. For additional information, see "Results and Discussion of Operations" in this Management's Discussion.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which are reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 13, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2025 and 2024.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by \$8.2 million and \$7.9 million for 2025 and 2024, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future long-term debt issuances. From time to time, we may enter into forward interest rate instruments to lock in long term interest costs and/or rates.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Management Policy which establishes guidelines for documenting management approval levels for credit limits, evaluating creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function, which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

The financial status of our banking partners is periodically assessed through traditional credit ratings provided by major credit rating agencies.

NiSOURCE INC.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Other Information

Critical Accounting Estimates

We apply certain accounting policies in accordance with GAAP, which require that we make estimates and judgments that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements. We evaluate our estimates on an ongoing basis. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. We believe the following represent the more significant items requiring the use of judgment in preparing our Consolidated Financial Statements:

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be billed and collected. Accordingly, certain expenses and credits subject to utility regulation or rate determination normally reflected in income may be deferred on the Consolidated Balance Sheets and recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. For additional information, refer to Note 12, "Regulatory Matters," in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. If we determine that the amounts included as regulatory assets are no longer probable of recovery, a charge to income would immediately be required to the extent of the unrecoverable amounts.

One of the more significant items recorded through the application of this accounting guidance is the regulatory overlay for JV accounting. The application of HLBV to consolidated VIEs generally results in the recognition of profit from the related JVs over a time frame that is different from when the regulatory return is earned. In accordance with the principles of ASC 980, we have recognized a regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. For additional information, refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," in the Notes to Consolidated Financial Statements.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

NiSOURCE INC.
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. For measurement of 2025 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 7.30% and 7.09% for our pension and other postretirement benefit plan assets, respectively. For measurement of 2026 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 7.13 % and 6.61% respectively, for our pension and other postretirement benefit plan assets.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We utilize a full yield curve approach to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 16, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements.

Typically, we use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations. We adopted Aon's U.S. Endemic Mortality Improvement scale MP-2021, accounting for both the near-term and long-term COVID-19 impacts.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

Change in Assumptions <i>(in millions)</i>	Impact on December 31, 2025 Projected Benefit Obligation Increase/(Decrease)	
	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	\$ (43.8)	\$ (16.9)
-50 basis points change in discount rate	47.1	18.3

Change in Assumptions <i>(in millions)</i>	Impact on 2025 Expense Increase/(Decrease) ⁽¹⁾	
	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	\$ (1.3)	\$ 0.1
-50 basis points change in discount rate	1.4	0.3
+50 basis points change in expected long-term rate of return on plan assets	(6.3)	(1.2)
-50 basis points change in expected long-term rate of return on plan assets	6.3	1.2

⁽¹⁾Before labor capitalization and regulatory deferrals.

Goodwill and Other Intangible Assets. We have six goodwill reporting units, comprised of the six state operating companies within both the Columbia Operations and NIPSCO Operations reportable segments. Our goodwill assets at December 31, 2025 were \$1,485.9 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was performed on May 1, 2025. A qualitative ("step 0") test was completed on May 1, 2025 for all reporting units. In the Step 0 analysis, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the applicable reporting units as compared to the baseline "step 1" fair value measurement performed May 1, 2024.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The results of this assessment indicated that it was more likely than not that the estimated fair value of the reporting units substantially exceeded the related carrying values of our reporting units; therefore, no "step 1" analysis was required and no impairment charges were indicated. Since the annual evaluation, there have been no indications that the fair values of the goodwill reporting units have decreased below the carrying values.

As noted above, application of the qualitative goodwill impairment test requires evaluating various events and circumstances to determine whether it is not more likely than not that the fair value of a reporting unit is less than its carrying amount. Although we believe all relevant factors were considered in the qualitative impairment analysis to reach the conclusion that goodwill is not impaired, significant changes in any one of the assumptions could potentially result in the recording of an impairment that could have significant impacts on the Consolidated Financial Statements.

See Note 10, "Goodwill," in the Notes to Consolidated Financial Statements for information regarding our 2025 analyses and assumptions.

Unbilled Revenue. We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon historical usage, customer rates and weather. As of December 31, 2025, we recorded \$465.2 million of customer accounts receivable for unbilled revenue. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Refer to Note 3, "Revenue Recognition," in the Notes to Consolidated Financial Statements for additional information regarding our significant judgments and estimates related to unbilled revenue recognition.

Income Taxes. The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require use of estimates and significant management judgment. Although we believe that current estimates for deferred tax assets and liabilities are reasonable, actual results could differ from these estimates for a variety of reasons, including reasonable projections of taxable income, the ability and intent to implement tax planning strategies if necessary, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Ultimate resolution or clarification of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

We account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement. We evaluate each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the consolidated financial statements. At December 31, 2025 and 2024, we had \$21.7 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

On a quarterly basis, we evaluate our deferred tax assets by considering current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. We establish a valuation allowance when we conclude it is more likely than not that all, or a portion, of a deferred tax asset will not be realized in future periods. Significant judgment is required to determine the amount of tax benefits expected to be realized. At December 31, 2025 and 2024, we had established \$14.8 million and \$6.4 million, respectively, of valuation allowances (net of federal benefit) related to federal Section 163(j) interest limitation carryforward and certain state net operating loss carryforwards. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures."

NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters - Impact of Rate Regulation on the Financial Statements – Refer to Notes 1, 9, and 12 to the financial statements

Critical Audit Matter Description

The Company's primary subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. These rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the manner in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged to and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the consolidated balance sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Company's subsidiaries' rates are determined and approved in regulatory proceedings based on an analysis of the subsidiaries' costs to provide utility service and a return on, and recovery of, the subsidiaries' investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The respective commission's regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the commission in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the commission will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation, specifically certain regulatory assets and liabilities at the Company's Northern Indiana Public Service Company LLC and Columbia Gas of Ohio, Inc. subsidiaries, as a critical audit matter due to the significant judgments made by management to support its assertions about certain account balances and the significant degree of subjectivity involved in assessing the likelihood of recovery of incurred costs in current or future rates due in part to uncertainty related to future decisions by the rate regulators. This required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and a significant degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of specialized rules to account for the effects of cost-based rate regulation related to the uncertainty of future decisions by the rate regulators, specifically the Indiana Utility Regulatory Commission (IURC) and the Public Utilities Commission of Ohio (PUCO), included the following, among others:

- We tested the effectiveness of management's controls over (1) the evaluation of the likelihood of (a) the recovery of costs deferred as regulatory assets in future periods, and (b) regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; and (2) the evaluation of Hypothetical Liquidation Book Value (HLBV) accounting for the company's renewable facility joint ventures and its impact on the Company's regulatory liability.
- We evaluated Northern Indiana Public Service Company LLC and Columbia Gas of Ohio, Inc.'s disclosures related to the financial statement impacts of rate regulation.
- We read relevant regulatory orders issued by the IURC and PUCO, including regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or a future reduction in rates based on precedents of the commissions' treatment of similar costs under similar circumstances. We evaluated this external information and compared to management's recorded regulatory asset and liability balances for completeness, including the implementation of a new base rate order at Northern Indiana Public Service Company LLC's electric business.
- We inspected minutes of the boards of directors for discussions of changes in legal, regulatory, or business factors which could impact management's conclusions with respect to the financial statement impacts of rate regulation.
- For the Northern Indiana Public Service Company LLC's electric base rate case that was approved in 2025, we inspected the order for any evidence that might contradict management's assertions related to recoverability of recorded assets.
- We inquired of management about property, plant, and equipment that may be abandoned with an emphasis on the generation strategy related to Northern Indiana Public Service Company LLC's R.M. Schahfer and Michigan City Generating Stations. We inspected minutes of the board of directors, regulatory orders, the Department of Energy's

NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Order Under Federal Power Act Section 202(c), and other filings with the IURC to identify evidence that may contradict management's assertion regarding probability of abandonment.

- We read the relevant regulatory orders issued by the IURC for the Company's renewable energy investments held within joint ventures. We evaluated the appropriateness of recognizing a regulatory liability for timing differences between the profit allocated under the HLBV accounting method and the allowed earnings included in rates for these joint ventures. We also evaluated the appropriateness of the offset to the regulatory liability recorded in depreciation expense.

/s/ DELOITTE & TOUCHE LLP

Columbus, Ohio

February 11, 2026

We have served as the Company's auditor since 2002.

NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

STATEMENTS OF CONSOLIDATED INCOME

Year Ended December 31, <i>(in millions, except per share amounts)</i>	2025	2024	2023
Operating Revenues			
Customer revenues	\$ 6,522.8	\$ 5,282.9	\$ 5,347.8
Other revenues	119.4	172.2	157.6
Total Operating Revenues	6,642.2	5,455.1	5,505.4
Operating Expenses			
Cost of energy	1,584.4	1,132.2	1,533.3
Operation and maintenance	1,710.2	1,515.2	1,494.9
Depreciation and amortization	1,167.6	1,043.2	908.2
Loss on impairment of assets	0.7	6.1	—
Loss (gain) on sale of assets, net	(0.1)	2.9	2.9
Other taxes	344.1	300.0	270.6
Total Operating Expenses	4,806.9	3,999.6	4,209.9
Operating Income	1,835.3	1,455.5	1,295.5
Other Income (Deductions)			
Interest expense, net	(639.0)	(517.2)	(489.6)
Other, net	20.1	64.5	8.0
Total Other Deductions, Net	(618.9)	(452.7)	(481.6)
Income before Income Taxes	1,216.4	1,002.8	813.9
Income Taxes	203.8	158.1	139.5
Net Income	1,012.6	844.7	674.4
Net income (loss) attributable to noncontrolling interest	83.1	84.3	(39.9)
Net Income attributable to NiSource	929.5	760.4	714.3
Preferred dividends	—	(6.7)	(42.8)
Preferred redemption premium	—	(14.0)	(9.8)
Net Income Available to Common Shareholders	\$ 929.5	\$ 739.7	\$ 661.7
Earnings Per Share			
Basic Earnings Per Share	\$ 1.96	\$ 1.63	\$ 1.59
Diluted Earnings Per Share	\$ 1.95	\$ 1.62	\$ 1.48
Basic Average Common Shares Outstanding	472.9	454.2	416.1
Diluted Average Common Shares	474.5	456.0	447.9

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NiSOURCE INC.**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)****STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME**

Year Ended December 31, <i>(in millions, net of taxes)</i>	2025	2024	2023
Net Income	\$ 1,012.6	\$ 844.7	\$ 674.4
Other comprehensive income:			
Net unrealized gain on available-for-sale securities ⁽¹⁾	4.1	3.3	3.9
Net unrealized loss on cash flow hedges ⁽²⁾	(0.4)	(0.4)	(0.2)
Unrecognized pension and OPEB benefit (costs) ⁽³⁾	20.5	0.3	(0.2)
Total other comprehensive income	24.2	3.2	3.5
Total Comprehensive Income	\$ 1,036.8	\$ 847.9	\$ 677.9

⁽¹⁾ Net unrealized gain on available-for-sale securities, net of \$1.1 million tax expense, \$0.9 million tax expense and \$1.0 million tax expense in 2025, 2024 and 2023, respectively.

⁽²⁾ Net unrealized loss on derivatives qualifying as cash flow hedges, net of \$0.1 million tax benefit, \$0.1 million tax benefit and \$0.1 million tax benefit in 2025, 2024 and 2023, respectively.

⁽³⁾ Unrecognized pension and OPEB benefit (costs), net of \$4.4 million tax expense, \$0.3 million tax expense and \$0.1 million tax benefit in 2025, 2024 and 2023, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NI SOURCE INC.
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)
CONSOLIDATED BALANCE SHEETS

<i>(in millions)</i>	December 31, 2025	December 31, 2024
ASSETS		
Property, Plant and Equipment		
Plant	\$ 38,058.8	\$ 34,152.9
Accumulated depreciation and amortization	(9,370.6)	(8,699.0)
Net Property, Plant and Equipment⁽¹⁾	28,688.2	25,453.9
Investments and Other Assets		
Unconsolidated affiliates	8.1	6.5
Available-for-sale debt securities (amortized cost of \$145.8 and \$91.9, allowance for credit losses of \$0.0 and \$0.1, respectively)	146.1	86.7
Other investments	118.6	85.5
Total Investments and Other Assets	272.8	178.7
Current Assets		
Cash and cash equivalents	110.1	156.6
Restricted cash	25.6	42.0
Accounts receivable	1,238.1	987.9
Allowance for credit losses	(40.6)	(23.7)
Accounts receivable, net	1,197.5	964.2
Gas storage	252.0	179.6
Materials and supplies, at average cost	189.0	173.3
Electric production fuel, at average cost	8.5	36.2
Exchange gas receivable	66.0	45.7
Regulatory assets	274.2	319.9
Prepayments	149.3	138.5
Other current assets	105.0	24.2
Total Current Assets⁽¹⁾	2,377.2	2,080.2
Other Assets		
Regulatory assets	2,225.2	2,157.4
Goodwill	1,485.9	1,485.9
Deferred charges and other ⁽²⁾	809.4	432.0
Total Other Assets	4,520.5	4,075.3
Total Assets	\$ 35,858.7	\$ 31,788.1

⁽¹⁾Includes \$1,312.7 million and \$1,323.8 million in 2025 and 2024, respectively, of net property, plant and equipment assets, \$90.1 million and \$65.0 million in 2025 and 2024, respectively, of current assets of consolidated VIEs that may be used only to settle obligations of the consolidated VIEs. Refer to Note 4, "Noncontrolling Interests," for additional information.

⁽²⁾Includes \$305.4 million in 2025 of advanced deposits of project costs of consolidated VIEs that may be used only to settle obligations of the consolidated VIEs. Refer to Note 4, "Noncontrolling Interests," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NI SOURCE INC.
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)
CONSOLIDATED BALANCE SHEETS

<i>(in millions, except share amounts)</i>	December 31, 2025	December 31, 2024
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders' Equity		
Common stock - \$0.01 par value, 750,000,000 shares authorized; 478,432,058 and 469,822,472 shares outstanding, respectively	\$ 4.8	\$ 4.7
Treasury stock	(99.9)	(99.9)
Additional paid-in capital	9,866.6	9,521.5
Retained deficit	(315.2)	(711.7)
Accumulated other comprehensive loss	(6.2)	(30.4)
Total NiSource Stockholders' Equity	9,450.1	8,684.2
Noncontrolling interest in consolidated subsidiaries	2,209.8	1,984.1
Total Stockholders' Equity	11,659.9	10,668.3
Long-term debt, excluding amounts due within one year	15,457.8	12,074.5
Total Capitalization	27,117.7	22,742.8
Current Liabilities		
Current portion of long-term debt	19.7	1,281.2
Short-term borrowings	736.0	604.6
Accounts payable	1,124.5	863.1
Customer deposits and credits	283.4	268.8
Taxes accrued	228.8	173.4
Interest accrued	206.2	157.0
Asset retirement obligations	55.0	84.6
Exchange gas payable	125.4	91.8
Regulatory liabilities	260.1	150.5
Accrued compensation and employee benefits	246.8	268.2
Other accruals	171.5	170.2
Total Current Liabilities⁽¹⁾	3,457.4	4,113.4
Other Liabilities		
Deferred income taxes	2,500.1	2,281.6
Accrued liability for postretirement and postemployment benefits	153.1	207.5
Regulatory liabilities	1,513.3	1,431.2
Asset retirement obligations	781.9	698.6
Other noncurrent liabilities and deferred credits	335.2	313.0
Total Other Liabilities⁽¹⁾	5,283.6	4,931.9
Commitments and Contingencies (Refer to Note 19, "Other Commitments and Contingencies")		
Total Capitalization and Liabilities	\$ 35,858.7	\$ 31,788.1

⁽¹⁾Includes \$56.9 million and \$53.7 million in 2025 and 2024, respectively, of current liabilities, \$55.7 million and \$58.3 million in 2025 and 2024, respectively, of other liabilities, and finance leases of \$40.1 million and \$40.4 million in 2025 and 2024, respectively, of consolidated VIEs that creditors do not have recourse to our general credit. Refer to Note 4, "Noncontrolling Interests," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

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NI SOURCE INC.
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, (in millions)	2025		2024		2023	
Operating Activities						
Net Income	\$	1,012.6	\$	844.7	\$	674.4
Adjustments to Reconcile Net Income to Net Cash from Operating Activities:						
Depreciation and amortization		1,167.6		1,043.2		908.2
Deferred income taxes and investment tax credits		235.8		168.0		134.1
Stock compensation expense and 401(k) profit sharing contribution		50.9		43.6		33.5
Payments for asset retirement obligations		(73.0)		(72.5)		(41.6)
Other adjustments		24.8		(49.9)		(15.0)
Changes in Assets and Liabilities:						
Accounts receivable		(273.4)		(101.5)		184.1
Gas storage and other inventories		(60.3)		102.0		233.9
Accounts payable		131.8		71.5		(171.8)
Exchange gas receivable/payable		135.8		(133.5)		126.5
Other accruals		67.9		9.5		(102.9)
Prepayments and other current assets		(37.3)		(75.9)		36.7
Regulatory assets/liabilities		55.7		(8.7)		(26.2)
Postretirement and postemployment benefits		(46.1)		(64.3)		(22.0)
Deferred charges and other noncurrent assets		(33.5)		(20.8)		(10.1)
Other noncurrent liabilities and deferred credits		3.0		26.1		(6.7)
Net Cash Flows from Operating Activities		2,362.3		1,781.5		1,935.1
Investing Activities						
Capital expenditures		(2,782.3)		(2,614.0)		(2,645.8)
Cost of removal		(188.3)		(166.8)		(160.8)
Purchases of available-for-sale securities		(93.9)		(17.8)		(42.8)
Sales of available-for-sale securities		39.3		93.2		39.9
Milestone and final payments to renewable generation asset developers		(1,098.7)		(482.0)		(761.4)
Advanced deposits for project costs		(373.8)		(29.0)		—
Other investing activities		(26.4)		3.4		(0.7)
Net Cash Flows used for Investing Activities		(4,524.1)		(3,213.0)		(3,571.6)
Financing Activities						
Proceeds from issuance of long-term debt		3,352.0		2,229.5		1,488.7
Repayments of finance lease obligations		(22.0)		(25.6)		(33.1)
Repayments of long-term debt		(1,260.0)		—		—
Repayment of short term credit agreements		—		(1,650.0)		—
Issuance of short term credit agreements		—		—		650.0
Net change in commercial paper and other short-term borrowings		131.4		(794.0)		636.4
Issuance of common stock, net of issuance costs		312.1		612.6		12.9
Redemption of preferred stock		—		(486.1)		(393.9)
Preferred stock redemption premium		—		(14.0)		(6.2)
Payment of obligation to renewable generation asset developer		—		—		(347.2)
Equity costs, premiums and other debt related costs		(26.8)		(67.3)		(30.2)
Contributions from NIPSCO and GenCo minority interest holders		231.4		99.5		2,161.9
Distributions to NIPSCO minority interest holders		(74.6)		(50.3)		—
Contributions from tax equity partners		—		—		240.9
Distributions to tax equity partners		(14.2)		(16.1)		(14.1)
Dividends paid - common stock		(530.4)		(481.0)		(413.5)
Dividends paid - preferred stock		—		(8.2)		(43.8)
Contract liability payment		—		—		(66.6)
Net Cash Flows (used for) from Financing Activities		2,098.9		(651.0)		3,842.2
Change in cash, cash equivalents and restricted cash		(62.9)		(2,082.5)		2,205.7
Cash, cash equivalents and restricted cash at beginning of period		198.6		2,281.1		75.4
Cash, Cash Equivalents and Restricted Cash at End of Period	\$	135.7	\$	198.6	\$	2,281.1
Reconciliation to Balance Sheet						
Cash and cash equivalents		110.1		156.6		2,245.4
Restricted cash		25.6		42.0		35.7
Total Cash, Cash Equivalents and Restricted Cash		135.7		198.6		2,281.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NiSOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

<i>(in millions)</i>	Common Stock	Preferred Stock ⁽¹⁾	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance as of December 31, 2022	\$ 4.2	\$ 1,546.5	\$ (99.9)	\$ 7,375.3	\$ (1,213.6)	\$ (37.1)	\$ 326.4	\$ 7,901.8
Comprehensive Income:								
Net Income (Loss)	—	—	—	—	714.3	—	(39.9)	674.4
Other comprehensive income, net of tax	—	—	—	—	—	3.5	—	3.5
Dividends:								
Common stock (\$1.00 per share)	—	—	—	—	(414.1)	—	—	(414.1)
Preferred stock (See Note 6)	—	—	—	—	(43.8)	—	—	(43.8)
Noncontrolling Interests:								
Issuance of noncontrolling interests ⁽²⁾	—	—	—	809.6	—	—	1,361.1	2,170.7
Contributions from noncontrolling interest ⁽³⁾	—	—	—	—	—	—	233.2	233.2
Distributions to noncontrolling interest	—	—	—	—	—	—	(14.1)	(14.1)
Stock issuances (redemptions):								
Equity Units	0.3	(666.5)	—	666.2	—	—	—	—
Series A Preferred stock redemption	—	(393.9)	—	—	—	—	—	(393.9)
Series A Preferred stock redemption premium	—	—	—	—	(9.8)	—	—	(9.8)
Employee stock purchase plan	—	—	—	5.9	—	—	—	5.9
Long-term incentive plan	—	—	—	12.6	—	—	—	12.6
401(k) and profit sharing	—	—	—	9.9	—	—	—	9.9
Balance as of December 31, 2023	\$ 4.5	\$ 486.1	\$ (99.9)	\$ 8,879.5	\$ (967.0)	\$ (33.6)	\$ 1,866.7	\$ 10,136.3
Comprehensive Income:								
Net Income	—	—	—	—	760.4	—	84.3	844.7
Other comprehensive income, net of tax	—	—	—	—	—	3.2	—	3.2
Dividends:								
Common stock (\$1.06 per share)	—	—	—	—	(483.0)	—	—	(483.0)
Preferred stock (See Note 6)	—	—	—	—	(8.1)	—	—	(8.1)
Noncontrolling Interests:								
Contributions from noncontrolling interest ⁽³⁾	—	—	—	—	—	—	99.5	99.5
Distributions to noncontrolling interest	—	—	—	—	—	—	(66.4)	(66.4)
Stock issuances (redemptions):								
Series B and B-1 Preferred stock redemption	—	(486.1)	—	—	—	—	—	(486.1)
Series B and B-1 Preferred stock redemption premium	—	—	—	—	(14.0)	—	—	(14.0)
Employee stock purchase plan	—	—	—	6.4	—	—	—	6.4
Long-term incentive plan	—	—	—	26.6	—	—	—	26.6
401(k) and profit sharing	—	—	—	9.2	—	—	—	9.2
ATM Program	0.2	—	—	599.8	—	—	—	600.0
Balance as of December 31, 2024	\$ 4.7	\$ —	\$ (99.9)	\$ 9,521.5	\$ (711.7)	\$ (30.4)	\$ 1,984.1	\$ 10,668.3
Comprehensive Income:								
Net Income	—	—	—	—	929.5	—	83.1	1,012.6
Other comprehensive income, net of tax	—	—	—	—	—	24.2	—	24.2
Dividends:								
Common stock (\$1.12 per share)	—	—	—	—	(533.0)	—	—	(533.0)
Noncontrolling Interests:								
Contributions from noncontrolling interest ⁽³⁾	—	—	—	—	—	—	231.4	231.4
Distributions to noncontrolling interests	—	—	—	—	—	—	(88.8)	(88.8)
Stock issuances (redemptions):								
Employee stock purchase plan	—	—	—	7.4	—	—	—	7.4
Long-term incentive plan	—	—	—	30.2	—	—	—	30.2
401(k) and profit sharing	—	—	—	9.4	—	—	—	9.4
ATM Program	0.1	—	—	298.1	—	—	—	298.2
Balance as of December 31, 2025	\$ 4.8	\$ —	\$ (99.9)	\$ 9,866.6	\$ (315.2)	\$ (6.2)	\$ 2,209.8	\$ 11,659.9

⁽¹⁾ Series A, Series B and Series C shares had an aggregate liquidation preference of \$400M, \$500M and \$863M, respectively.

⁽²⁾ Relates to the NIPSCO Minority Interest Transaction. See Note 4, "Noncontrolling Interests," for additional discussion.

⁽³⁾ Contributions from NIPSCO and GenCo (starting in 2025) minority interest holders included in noncontrolling interest is net of transaction costs.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

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NI SOURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY (continued)

<i>(in thousands)</i>	Preferred	Common		
	Shares	Shares	Treasury	Outstanding
Balance as of December 31, 2022	1,303	416,106	(3,963)	412,143
Issued:				
Employee stock purchase plan	—	216	—	216
Long-term incentive plan	—	758	—	758
401(k) and profit sharing plan	—	366	—	366
Equity Units ⁽¹⁾	—	33,899	—	33,899
Redeemed:				
Equity Units ⁽¹⁾	(863)	—	—	—
Series A Preferred Stock	(400)	—	—	—
Balance as of December 31, 2023	40	451,345	(3,963)	447,382
Issued:				
Employee stock purchase plan	—	218	—	218
Long-term incentive plan	—	769	—	769
401(k) and profit sharing plan	—	309	—	309
ATM Program	—	21,144	—	21,144
Redeemed:				
Series B and B-1 Preferred Stock	(40)	—	—	—
Balance as of December 31, 2024	—	473,785	(3,963)	469,822
Issued:				
Employee stock purchase plan	—	186	—	186
Long-term incentive plan	—	772	—	772
401(k) and profit sharing plan	—	231	—	231
ATM Program	—	7,421	—	7,421
Balance as of December 31, 2025	—	482,395	(3,963)	478,432

⁽¹⁾See Note 6, "Equity," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 3.8 million customers in six states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us, our majority-owned subsidiaries, and VIEs of which we are the primary beneficiary after the elimination of all intercompany accounts and transactions.

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trusts to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, and holdbacks related to certain joint venture development agreements which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from their last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, weather and reasonable and supportable forecasts. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical collection experience, current market conditions and reasonable and supportable forecasts. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable, including amounts related to unbilled revenues.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within "Available-for-sale debt securities" and "Other investments" on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. At each reporting period these investments are qualitatively and quantitatively assessed to determine whether a decline in fair value below the amortized cost basis has resulted from a credit loss or other factors. Impairments related to credit loss are recorded through an allowance for credit losses. Impairments that are not related to credit losses are included in other comprehensive income and are reflected in the Statements of Consolidated Income. No material impairment charges were recorded for the years ended December 31, 2025, 2024 or 2023. Refer to Note 14, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be billed and collected. Certain expenses and credits subject to utility regulation or rate determination that would normally be reflected in income for non-regulated entities are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

We continually evaluate whether or not our operations are within the scope of ASC 980 and rate regulations. As part of that analysis, we evaluate probability of recovery for our regulatory assets. In management's opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 12, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. Our rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties, as approved by the appropriate regulators.

Non-utility property, consisting of renewable generation assets owned by JVs of which we are the primary beneficiary and certain retired regulatory assets described below, is generally depreciated over the life of the associated assets. Refer to Note 9, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies where provided for in rates, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our consolidated pre-tax rate for AFUDC was 3.6% in 2025, 4.8% in 2024 and 3.9% in 2023.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the gross amounts are classified as "Non-Utility and Other" as described in Note 9, "Property, Plant and Equipment." If the asset is no longer operating but still subject to recovery, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

External and internal costs associated with on-premises computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years. External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets, with the associated internal-use software capitalized to plant if we have a contractual right to take possession of the software at any time during the hosting period without significant penalty and it is feasible for us to either run the software on our own hardware or contract with another party unrelated to the vendor to host the software. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonably expected to be exercised.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches. See Note 10, "Goodwill," for additional information.

I. Accounts Receivable Transfer Programs. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2025 and 2024 Consolidated Balance Sheets. When amounts are securitized, the short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 7, "Short-Term Borrowings," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 12, "Regulatory Matters," for additional information.

K. Gas Storage and Other Inventories. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was \$42.5 million and \$43.8 million at December 31, 2025 and 2024, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was less than the stated LIFO cost by \$7.6 million at December 31, 2025 and was less than the stated LIFO cost by \$12.8 million at December 31, 2024. As all LIFO inventory costs are collected from customers through our rate-regulated subsidiaries, no inventory impairment has been recorded. Gas inventory valued using the weighted average cost methodology was \$209.5 million at December 31, 2025 and \$135.8 million at December 31, 2024.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology. Materials and supplies are charged to expense or capitalized to property, plant and equipment when issued.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Columbia Operations and NIPSCO Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under an exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as "Exchange gas receivable" or "Exchange gas payable" on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We do not offset the fair value amounts recognized for any of our derivative instruments against the fair value amounts recognized for the right to reclaim cash collateral or obligation to return cash collateral for derivative instruments executed with the same counterparty under a master netting arrangement. See Note 13, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Investment tax credits and production tax credits associated with regulated operations are deferred and amortized as a reduction to income tax expense over a 10 year period and 1 year period, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies' obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries generally file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to a tax sharing agreement under which income taxes recorded by each party represent amounts that would be owed had the party been separately subject to tax. Effective January 1, 2024, NIPSCO Accounts Receivable Corporation is no longer included in the consolidated group and now files a separate income tax return.

O. Pension Remeasurement. We utilize a third-party actuary for the purpose of performing actuarial valuations of our defined benefit plans. Annually, as of December 31, we perform a remeasurement for our defined benefit plans. Quarterly, we monitor for significant events, and if a significant event is identified, we perform a qualitative and quantitative assessment to determine if the resulting remeasurement would materially impact the NiSource financial statements. If material, an interim remeasurement is performed. See Note 16, "Pension and Other Postemployment Benefits," for additional information.

P. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations, including expenditures related to asset retirement obligations and cost of removal, when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in "Other accruals" for short-term portions of these liabilities and "Other noncurrent liabilities and deferred credits" for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 11, "Asset Retirement Obligations," and Note 19, "Other Commitments and Contingencies," for further information.

Q. Excise Taxes. As an agent for some state and local governments, we invoice and collect certain excise taxes levied by state and local governments on customers and record these amounts as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to "Other taxes" expense on the Statements of Consolidated Income.

R. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information.

S. Noncontrolling Interest. We maintain a controlling financial interest in certain of our less than wholly owned subsidiaries. We consolidate these subsidiaries as either voting interest entities or VIEs and present the third-party investors' portion of our net income (loss), net assets and comprehensive income (loss) as noncontrolling interest. Noncontrolling interest is included as a component of equity on the Consolidated Balance Sheet.

In December 2023, the NIPSCO Minority Interest Transaction closed and a 19.9% equity interest in NIPSCO Holdings II, the sole owner of NIPSCO, was issued to an affiliate of Blackstone. NIPSCO Holdings II does not meet the criteria of a VIE and instead is consolidated under the voting interest model in accordance with ASC 810 as we maintain control through a majority interest in NIPSCO Holdings II.

In October 2025, the GenCo Minority Interest Transaction closed and a 19.9% equity interest in Generation Holdings II, the sole owner of GenCo, was issued to affiliates of Blackstone. Generation Holdings II meets the criteria of a VIE and is consolidated in accordance with ASC 810 as we control the decisions that are significant to the VIE's ongoing operations and economic results (i.e., we are the primary beneficiary).

Refer to Note 4, "Noncontrolling Interests," for further discussion on the NIPSCO Minority Interest Transaction and GenCo Minority Interest Transaction.

We fund a portion of our renewable generation assets through JVs with tax equity partners. We consolidate these JVs in accordance with ASC 810 as they are VIEs in which we hold a variable interest, and we control decisions that are significant to the JVs' ongoing operations and economic results (i.e., we are the primary beneficiary).

These JVs are subject to profit sharing arrangements in which the allocation of the JVs' cash distributions and tax benefits to members is based on factors other than members' relative ownership percentages. As such, we utilize the HLBV method to allocate proceeds to each partner at the balance sheet date based on the liquidation provisions of the related JV's operating agreement and adjust the amount of the VIE's net income attributable to us and the noncontrolling tax equity member during the period.

In each reporting period, the application of HLBV to our consolidated VIEs results in a difference between the amount of profit from the consolidated JVs and the amount included in regulated rates. As discussed above in "F. Basis of Accounting for Rate-Regulated Subsidiaries," we are subject to the accounting and reporting requirements of ASC 980. In accordance with these principles, we recognize a regulatory liability or asset for amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The amounts recorded in income will ultimately reflect the amount allowed in regulated rates to recover our investments over the useful life of the projects. The offset to the regulatory liability or asset associated with our renewable investments included in regulated rates is recorded in "Depreciation expense" on the Statements of Consolidated Income.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

In September 2025, the FASB issued ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software. This pronouncement updates the guidance on capitalization of internal-use software, including removing the development stages utilized for evaluation of when certain activities are capital eligible. The ASU instead provides that an entity is required to start capitalizing eligible software

development costs when (1) management has authorized and committed to funding the software project and (2) it is probable that the project will be completed and the software will be used to perform the function intended, which is referred to as the “probable-to-complete recognition threshold”. This probable-to-complete threshold includes an evaluation of whether there is significant uncertainty associated with the development activities of the software. The ASU is effective for fiscal years beginning after December 15, 2027. We are currently evaluating the impacts this amendment will have on our internal-use software capitalization policy.

In November 2024, the FASB issued ASU 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40). This pronouncement requires disaggregated disclosure of income statement expenses for public business entities. The ASU requires disclosure in tabular format of disaggregation of relevant expense captions presented on the income statement by certain natural expense categories with certain related qualitative disclosures within the notes to the financial statements. The ASU does not change the expense captions an entity presents on the income statement. The ASU is effective for fiscal years beginning after December 15, 2026, and interim reporting periods within annual reporting periods beginning after December 15, 2027, as defined in ASU 2025-01, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40). We are currently evaluating the impacts this amendment will have on our required disclosures.

Recently Adopted Accounting Pronouncements

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. This pronouncement enhances required income tax disclosures. The pronouncement requires disclosure of specific categories and reconciling items included in the rate reconciliation, disaggregation between federal, state and local income taxes paid, and disclosure of income taxes paid by jurisdictions over a certain threshold. Additionally, the pronouncement eliminates certain required disclosures related to unrecognized tax benefits. We have adopted this ASU on a retrospective basis in the income tax footnote 15, for the year ended December 31, 2025.

3. Revenue Recognition

Customer Revenues. Substantially all of our revenues are tariff-based. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract, which creates enforceable rights and obligations. Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer deposits and credits" on the Consolidated Balance Sheets. Amounts in this account are reduced and revenue is recorded when customer usage exceeds payments received.

We have identified our performance obligations created under tariff-based sales as i) the commodity (natural gas or electricity, which includes generation and capacity) and ii) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company’s respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs, subject to reconciliation, and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in "Regulatory assets" or "Regulatory liabilities" on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. Distribution revenues are generally considered daily or "at-will" contracts as customers may cancel their service at any time (subject to notification requirements), and revenue generally represents the amount we are entitled to bill customers.

In addition to tariff-based sales, our gas distribution in both our Columbia Operations and NIPSCO Operations segments enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a gas distribution operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment, as well as by customer class. As of January 1, 2024, we have changed our reportable segments from Gas Distribution Operations and Electric Operations to Columbia Operations and NIPSCO Operations. Our historical segment disclosures have been recast to be consistent with the current presentation. For additional information see Note 21, "Business Segment Information".

The Columbia Operations segment provides regulated natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. The NIPSCO Operations segment provides regulated gas and electric service in northern Indiana for residential, commercial and industrial customers.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved mechanisms that allow for the adjustment of billings and revenue for certain approved programs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize alternative revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income as "Other revenues". When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

The tables below reconcile revenue disaggregation by customer class to segment revenue, as well as to revenues reflected on the Statements of Consolidated Income:

<i>Year Ended December 31, 2025 (in millions)</i>	Columbia Operations		NIPSCO Operations		Corporate and Other		Total
Gas Distribution							
Residential	\$	2,279.9	\$	708.0	\$	—	\$ 2,987.9
Commercial		763.7		270.0		—	1,033.7
Industrial		167.4		100.2		—	267.6
Off-system		75.8		—		—	75.8
Wholesale		2.1		—		—	2.1
Miscellaneous ⁽¹⁾		35.9		13.5		—	49.4
Subtotal	\$	3,324.8	\$	1,091.7	\$	—	\$ 4,416.5
Electric Generation and Power Delivery							
Residential	\$	—	\$	768.4	\$	—	\$ 768.4
Commercial		—		713.9		—	713.9
Industrial		—		578.3		—	578.3
Wholesale		—		45.1		—	45.1
Public Authority		—		9.5		—	9.5
Miscellaneous ⁽¹⁾		—		(8.9)		—	(8.9)
Subtotal	\$	—	\$	2,106.3	\$	—	\$ 2,106.3
Total Customer Revenues⁽²⁾		3,324.8		3,198.0		—	6,522.8
Other Revenues⁽³⁾		5.2		109.3		4.9	119.4
Total Operating Revenues	\$	3,330.0	\$	3,307.3	\$	4.9	\$ 6,642.2

⁽¹⁾Amounts included in Columbia Operations are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to revenue refunds, public repairs and property rentals.

⁽²⁾Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.

⁽³⁾Amounts included in Columbia Operations primarily relate to alternate revenue programs, including weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily relate to weather normalization adjustment mechanisms, MISO multi-value projects and revenue from non-jurisdictional transmission assets. Amounts included in Corporate and Other primarily relate to products and services revenue.

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Year Ended December 31, 2024 (in millions)	Columbia Operations		NIPSCO Operations		Corporate and Other		Total
Gas Distribution							
Residential	\$	1,833.8	\$	531.4	\$	—	\$ 2,365.2
Commercial		580.3		199.2		—	779.5
Industrial		144.2		79.0		—	223.2
Off-system		42.6		—		—	42.6
Wholesale		1.2		—		—	1.2
Miscellaneous ⁽¹⁾		26.3		15.4		—	41.7
Subtotal	\$	2,628.4	\$	825.0	\$	—	\$ 3,453.4
Electric Generation and Power Delivery							
Residential		—		649.9		—	649.9
Commercial		—		620.4		—	620.4
Industrial		—		499.1		—	499.1
Wholesale		—		38.3		—	38.3
Public Authority		—		8.1		—	8.1
Miscellaneous ⁽¹⁾		—		13.7		—	13.7
Subtotal	\$	—	\$	1,829.5	\$	—	\$ 1,829.5
Total Customer Revenues⁽²⁾	\$	2,628.4	\$	2,654.5	\$	—	\$ 5,282.9
Other Revenues⁽³⁾		74.8		96.5		0.9	172.2
Total Operating Revenues	\$	2,703.2	\$	2,751.0	\$	0.9	\$ 5,455.1

⁽¹⁾Amounts included in Columbia Operations are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to revenue refunds, public repairs and property rentals.

⁽²⁾Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.

⁽³⁾Amounts included in Columbia Operations primarily related to weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily relate to weather normalization adjustment mechanisms, MISO multi-value projects and revenue from non-jurisdictional transmission assets.

Year Ended December 31, 2023 (in millions)	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Gas Distribution				
Residential	\$ 1,827.5	\$ 635.0	\$ —	\$ 2,462.5
Commercial	598.9	249.0	—	847.9
Industrial	139.0	87.0	—	226.0
Off-system	60.6	—	—	60.6
Wholesale	1.6	—	—	1.6
Miscellaneous ⁽¹⁾	33.4	14.8	—	48.2
Subtotal	\$ 2,661.0	\$ 985.8	\$ —	\$ 3,646.8
Electric Generation and Power Delivery				
Residential	\$ —	\$ 583.9	\$ —	\$ 583.9
Commercial	—	578.1	—	578.1
Industrial	—	474.1	—	474.1
Wholesale	—	32.0	—	32.0
Public Authority	—	11.5	—	11.5
Miscellaneous ⁽¹⁾	—	21.4	—	21.4
Subtotal	\$ —	\$ 1,701.0	\$ —	\$ 1,701.0
Total Customer Revenues⁽²⁾	\$ 2,661.0	\$ 2,686.8	\$ —	\$ 5,347.8
Other Revenues⁽³⁾	72.9	83.9	0.8	157.6
Total Operating Revenues	\$ 2,733.9	\$ 2,770.7	\$ 0.8	\$ 5,505.4

⁽¹⁾Amounts included in Columbia Operations are primarily related to earnings share mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to late fees, property rentals, revenue refunds and adjustments.

⁽²⁾Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.

⁽³⁾Amounts included in Columbia Operations primarily related to weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily related to MISO multi-value projects and revenue from non-jurisdictional transmission assets.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of their last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, and weather. A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, primarily from November through March, revenues and receivables from gas sales are more significant than in other months. The opening and closing balances of customer receivables for the year ended December 31, 2025, are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)	Customer Accounts Receivable, Unbilled (less reserve)
Balance as of December 31, 2024	\$ 525.1	\$ 408.1
Balance as of December 31, 2025	698.8	465.2

Utility revenues are billed to customers monthly on a cycle basis. We expect that substantially all customer accounts receivable will be collected following customer billing, as this revenue consists primarily of periodic, tariff-based billings for service and usage. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. Our regulated operations also utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectability. It is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations.

Allowance for Credit Losses. To evaluate for expected credit losses, customer account receivables are pooled based on similar risk characteristics, such as customer type, geography, payment terms, and related macro-economic risks. Expected credit losses are established using a model that considers historical collections experience, current information, and reasonable and

supportable forecasts. Internal and external inputs are used in our credit model including, but not limited to, revenue projections, actual charge-offs data, recoveries data, shut-offs, security deposits and final bill data. We continuously evaluate available information relevant to assessing collectability of current and future receivables. We evaluate creditworthiness of specific customers periodically or following changes in facts and circumstances. When we become aware of a specific commercial or industrial customer's inability to pay, an allowance for expected credit losses is recorded for the relevant amount. We also monitor other circumstances that could affect our overall expected credit losses including, but not limited to, creditworthiness of overall population in service territories, adverse conditions impacting an industry sector, and current economic conditions. Bad debt expense for the year ended December 31, 2025 was \$16.5 million higher than the prior year primarily due to increases in aged receivables and anticipated higher delinquencies following colder weather in the fourth quarter.

At each reporting period, we record expected credit losses to an allowance for credit losses account. When deemed to be uncollectible, customer accounts are written-off. A rollforward of our allowance for credit losses as of December 31, 2025 and December 31, 2024, are presented in the tables below:

<i>(in millions)</i>	Columbia Operations		NIPSCO Operations		Corporate and Other		Total
Balance as of December 31, 2024	\$	9.8	\$	13.9	\$	—	\$ 23.7
Current period provisions		42.3		25.0		—	67.3
Write-offs charged against allowance		(50.8)		(15.0)		—	(65.8)
Recoveries of amounts previously written off		14.3		1.1		—	15.4
Balance as of December 31, 2025	\$	15.6	\$	25.0	\$	—	\$ 40.6

<i>(in millions)</i>	Columbia Operations		NIPSCO Operations		Corporate and Other		Total
Balance as of December 31, 2023	\$	10.2	\$	11.9	\$	0.8	\$ 22.9
Current period provisions		26.7		12.1		—	38.8
Write-offs charged against allowance		(43.9)		(11.0)		(0.8)	(55.7)
Recoveries of amounts previously written off		16.8		0.9		—	17.7
Balance as of December 31, 2024	\$	9.8	\$	13.9	\$	—	\$ 23.7

4. Noncontrolling Interests

Variable Interest Entities.

A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for information on our accounting policy for the VIEs.

NIPSCO is the managing member and operator of two wind JVs, Rosewater and Indiana Crossroads Wind, which have 102 MW and 302 MW of nameplate capacity, respectively. NIPSCO is also a managing member and operator of two solar JVs, Indiana Crossroads Solar and Dunns Bridge I, which have a nameplate capacity of 200 MW and 265 MW, respectively. We have determined that these JVs are VIEs. NIPSCO controls decisions that are significant to these entities' ongoing operations and economic results. Therefore, we have concluded that NIPSCO is the primary beneficiary and have consolidated all four entities.

Members of each respective JV include NIPSCO (who is the managing member) and a tax equity partner. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partner in varying percentages by category and over the life of the partnership. NIPSCO and each tax equity partner contributed cash to the respective JV. Once the tax equity partner has earned their negotiated rate of return and the JV has reached a stated contractual date, NIPSCO has the option to purchase the remaining interest in the respective JV from the tax equity partner. NIPSCO has an obligation to purchase 100% of the electricity generated by each commercially operational JV.

We did not provide any financial or other support for the JVs during the year that was not contractually required.

Our Consolidated Balance Sheets included the following assets and liabilities associated with the JV VIEs.

<i>(in millions)</i>	December 31, 2025	December 31, 2024
Net Property, Plant and Equipment	\$ 1,273.0	\$ 1,323.8
Current assets	27.6	65.0
Total assets ⁽¹⁾⁽²⁾	1,300.6	1,388.8
Current liabilities	16.1	53.7
Asset retirement obligations	55.7	58.3
Finance lease obligations	40.1	40.4
Total liabilities ⁽¹⁾⁽²⁾	\$ 111.9	\$ 152.4

⁽¹⁾The assets of each VIE represent assets of a consolidated VIE that can be used only to settle obligations of the respective consolidated VIE. The creditors of the liabilities of the VIEs do not have recourse to the general credit of the primary beneficiary.

⁽²⁾In addition to the amounts disclosed above there is a de minimis amount of other noncurrent assets and liabilities at Rosewater as of December 31, 2025.

GenCo Minority Interest Transaction. In October 2025, NiSource issued a 19.9% equity interest in Generation Holdings II, the sole owner of GenCo, to BIP Orion Holdco L.P. and BIP Orion Holdco II L.P., affiliates of Blackstone (collectively, “Blackstone Investor”), in exchange for \$35.2 million in cash contributions to Generation Holdings II through the Generation Holdings II LLC Agreement. Generation Holdings II is the sole owner of GenCo. Generation Holding II is considered a VIE as it passes the variability of its operating results through to its shareholders (Generation Holdings I and Blackstone Investor) and has insufficient equity to finance its activities without additional subordinated financial support. The sole purpose of the VIE is to own and operate GenCo which will acquire and build generation assets and provide capacity and electricity to support data center customers. Generation Holdings II and its wholly owned subsidiary, GenCo, is a consolidated VIE, as we have the power to direct the significant decision-making activities that most impact the ongoing operations and economic performance of the entity (i.e., we are the primary beneficiary) including business development and operating decisions.

The Generation Holdings II LLC Agreement establishes, among other things, governance rights, exit rights, requirements for additional capital contributions, mechanics for distributions, and other arrangements for Generation Holdings II. Specifically, under the terms of the Generation Holdings II LLC Agreement, Blackstone Investor will provide up to \$1.325 billion in additional capital contributions over a seven-year period, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof. Under the Generation Holdings II LLC Agreement, Blackstone Investor is entitled to appoint two directors to the board of directors of Generation Holdings II (the “Board”) so long as Blackstone Investor (together with any approved affiliate) holds at least a 17.5% Percentage Interest (as defined in the Generation Holdings II LLC Agreement). The Board is comprised of seven directors, two appointed by Blackstone Investor and five appointed by NiSource. The Generation Holdings II LLC Agreement also contains certain investor protections, including, among other things, requiring Blackstone Investor approval for Generation Holdings II to take certain major actions outside of the normal course of business. In addition, the Generation Holdings II LLC Agreement contains certain terms surrounding transfer rights and other obligations applicable to both Blackstone Investor and NiSource. Under the Generation Holdings II LLC Agreement, Generation Holdings II has agreed that, so long as Blackstone Investor holds a 14.9% or greater percentage interest in Generation Holdings II, Generation Holdings II and/or its subsidiaries and NIPSCO Holdings II and/or its subsidiaries shall be the exclusive vehicles for all power, storage and generation requirements for data center customers within NIPSCO’s service territory. The Generation Holdings II LLC Agreement also establishes that NiSource will be attributed 80.1% of any profit or loss from Generation Holdings II, through its wholly owned subsidiary GenCo, with the Blackstone Investor being attributed the remaining 19.9% of any profit or loss.

For the twelve months ended December 31, 2025, Generation Holdings I contributed \$344.9 million in cash and assets and the Blackstone Investor contributed \$76.9 million in cash to Generation Holdings II. For the twelve months ended December 31, 2025, Generation Holdings I received a distribution of \$35.2 million from Generation Holdings II.

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Our Consolidated Balance Sheets included the following assets and liabilities associated with GenCo:	December 31, 2025
<i>(in millions)</i>	
Net Property, Plant and Equipment	\$ 39.7
Current assets	62.5
Other assets	305.4
Total assets ⁽¹⁾	407.6
Current liabilities	40.8
Total liabilities ⁽¹⁾	\$ 40.8

⁽¹⁾The assets of each VIE represent assets of a consolidated VIE that can be used only to settle obligations of the respective consolidated VIE. The creditors of the liabilities of the VIEs do not have recourse to the general credit of the primary beneficiary.

Voting Interest Entities

NIPSCO Minority Interest Transaction. In December 2023, we consummated the NIPSCO Minority Interest Transaction for a capital contribution of \$2.16 billion in cash. The difference between the \$2.16 billion consideration received and the \$1.36 billion carrying value of the noncontrolling interest claim on net assets was recorded to additional paid-in capital, net of \$54.7 million in transaction costs and a \$63.5 million income tax benefit. We retain a controlling financial interest in NIPSCO Holdings II and its subsidiaries and consolidate their financial results. For the twelve months ending December 31, 2025, we received \$154.4 million of contributions and made \$74.6 million of distributions to our NIPSCO minority interest holders. For the twelve months ending December 31, 2024 we received \$99.5 million of contributions and made \$50.3 million of distributions to our NIPSCO minority interest holders. See Note 19, "Other Commitments and Contingencies - E. Other Matters," for a detailed discussion of the NIPSCO Holdings II LLC Agreement and governance structure.

In October 2025, the members of NIPSCO Holdings II entered into the Amended LLC Agreement, which, among other changes, increased the amount and time period for additional mandatory capital contributions required to be contributed by Blackstone Investor by \$175 million and seven years, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof, and amended certain provisions to facilitate NIPSCO Holdings II and its subsidiaries' provision of electric service to data center customers (and related activities) and their related contracts and arrangements with Generation Holdings II and its subsidiaries.

5. Earnings Per Share

The calculations of basic and diluted EPS are based on the weighted average number of shares of common stock and potential common stock outstanding during the period. Diluted EPS includes the incremental effects of the various long-term incentive compensation plans and ATM forward sale agreements under the treasury stock method when the impact would be dilutive. For the purposes of determining diluted EPS, for the twelve months ended December 31, 2023, the shares underlying the purchase contracts included within the Equity Units were included in the calculation of potential common stock outstanding using the if-converted method under US GAAP and we assumed share settlement of the remaining purchase contract payment balance from our Equity Units based on the average share price during the period. This method assumes conversion at the beginning of the reporting period, or at time of issuance, if later. The purchase contracts were settled on December 1, 2023. For the purchase contracts, the number of shares of our common stock that would have been issuable at the end of each reporting period prior to the settlement date were reflected in the denominator of our diluted EPS calculation. A numerator adjustment was reflected in the calculation of diluted EPS for interest expense incurred in 2023, net of tax, related to the purchase contracts.

The shares underlying the Series C Mandatory Convertible Preferred Stock included within the Equity Units were contingently convertible as the conversion was contingent on a successful remarketing. Contingently convertible shares where conversion was not tied to a market price trigger were excluded from the calculation of diluted EPS until such time as the contingency had been resolved under the if-converted method. The unsuccessful remarketing resolved the contingency and no shares were reflected in the denominator for the years ended December 31, 2023, for the calculation of diluted EPS.

We began using the two-class method of computing earnings per share in 2023 because we have participating securities in the form of non-vested restricted stock units with a non-forfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

Basic net income per share is computed by dividing net income available to common shareholders by the weighted-average number of shares of common stock outstanding during the period. Diluted net income per share is computed by giving effect to all potential shares of common stock, to the extent they are dilutive. Refer to Note 6, "Equity," for additional information.

The following table presents the calculation of our basic and diluted EPS:

Year Ended December 31, (in millions, except per share amounts)	2025	2024	2023
Numerator:			
Net Income Available to Common Shareholders	\$ 929.5	\$ 739.7	\$ 661.7
Less: Income allocated to participating securities	2.6	1.6	0.6
Net Income Available to Common Shareholders - Basic	\$ 926.9	\$ 738.1	\$ 661.1
Add: Dilutive effect of Equity Units	—	—	1.4
Net Income Available to Common Shareholders - Diluted	\$ 926.9	\$ 738.1	\$ 662.5
Denominator:			
Average common shares outstanding - Basic	472.9	454.2	416.1
Dilutive potential common shares:			
Equity Units purchase contracts	—	—	29.8
Equity Units purchase contract payment balance	—	—	0.9
Shares contingently issuable under employee stock plans	1.2	0.9	0.7
Shares restricted under employee stock plans	0.3	0.3	0.4
ATM Forward sale agreements	0.1	0.6	—
Average Common Shares - Diluted	474.5	456.0	447.9
Earnings per common share:			
Basic	\$ 1.96	\$ 1.63	\$ 1.59
Diluted	\$ 1.95	\$ 1.62	\$ 1.48

6. Equity

Holders of shares of our common stock are entitled to receive dividends when, as, and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have certain debt covenants that could restrict our ability to pay dividends or potentially limit the amount of dividends we could pay in order to maintain compliance with these covenants. Refer to Note 8, "Long-Term Debt," for more information. As of December 31, 2025, these covenants did not restrict our ability to pay dividends or the amount of dividends that were available to be paid.

There is no preferred stock outstanding as of December 31, 2025.

Common and preferred stock activity for 2025, 2024 and 2023 is described further below.

Details of our 2024 ATM program are summarized below:

- In February 2024, we entered into eight separate equity distribution agreements providing for the sale of up to an aggregate of \$900.0 million of our common stock.
- During 2024, we executed and settled four forward sale agreements. Under these agreements, we issued 21,143,900 shares resulting in net proceeds of \$600.3 million.
- In February 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,000,000 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$40.10 per share. In September 2025, we settled the forward sale agreement in shares for \$80.0 million, based on a net price of \$40.02 per share.

- In March 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 1,707,320 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$41.00 per share. In September 2025, we settled the forward sale agreement in shares for \$69.9 million, based on a net price of \$40.92 per share.
- In June 2025, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,518,393 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$39.71 per share. In September 2025, we settled the forward sale agreement in shares for \$99.1 million, based on a net price of \$39.36 per share.
- In October 2025, with the commencement of our 2025 ATM program discussed below, we terminated the equity distribution agreements entered into in February 2024 in connection with the 2024 ATM program.

Details of our 2025 ATM program are summarized below:

- In October 2025, we entered into eleven separate equity distribution agreements providing for the sale of up to an aggregate of \$1.5 billion of our common stock.
- In October 2025, we executed a direct sale agreement of 1,195,029 shares at a price of \$41.84 resulting in net proceeds of \$49.6 million received in November 2025.
- In October 2025, we executed a forward sale agreement, which allows us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 2,390,057 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of \$41.84 per share. We may settle the forward sale agreement in shares, cash or net shares by October 2026. Had we settled all the shares under the forward sale agreement at December 31, 2025, we would have received approximately \$99.7 million, based on a net price of \$41.73 per share.
- As of December 31, 2025, the 2025 ATM program inclusive of the forward sale agreement had approximately \$1.35 billion of equity capacity available. The 2025 ATM program expires in December 2028.

Series A Preferred Stock. During 2023, there were \$28.25 dividends declared per share for the Series A Preferred Stock. There were no dividends declared per share for the Series A Preferred Stock during 2024 and 2025.

In June 2023, we redeemed all 400,000 outstanding shares of Series A Preferred Stock for a redemption price of \$1,000 per share or \$400.0 million in total.

Series B and B-1 Preferred Stock. During 2024 and 2023, dividends declared per share for the Series B Preferred Stock were \$406.25 and \$1,625.0, respectively. There were no dividends declared per share for the Series B Preferred Stock during 2025.

In March 2024, we redeemed all 20,000 outstanding shares of Series B Preferred Stock for a redemption price of \$25,000 per share and all 20,000 outstanding shares of Series B-1 Preferred Stock for a redemption price of \$0.01 per share or \$500.0 million in total. Following the redemption, dividends ceased to accrue on the shares of Series B Preferred Stock, shares of the Series B Preferred Stock and Series B-1 Preferred Stock were no longer deemed outstanding and all rights of the holders of such shares of Series B Preferred Stock and Series B-1 Preferred Stock terminated. In conjunction with the redemption, we recorded a \$14.0 million preferred stock redemption premium, calculated as the difference between the carrying value on the redemption date of the Series B Preferred Stock and Series B-1 Preferred Stock and the total amount of consideration paid to redeem, which was recorded as a reduction to retained earnings during the first quarter of 2024. We did not recognize an excise tax liability under the IRA in connection with this redemption as we issued common stock in 2024 in excess of the fair value of the Series B Preferred Stock and Series B-1 Preferred Stock redeemed.

In March 2024, we filed a Certificate of Elimination to our Amended and Restated Certificate of Incorporation with the Secretary of State of Delaware to eliminate from the Amended and Restated Certificate of Incorporation all matters set forth in the Certificate of Designations with respect to the Series B Preferred Stock and the Certificate of Designations with respect to

the Series B-1 Preferred Stock. As a result, the 20,000 shares that were previously designated as Series B Preferred Stock and the 20,000 shares that were previously designated as Series B-1 Preferred Stock were returned to the status of authorized but unissued shares of preferred stock, par value \$0.01 per share, without designation as to series. The Certificate of Elimination does not change the total number of authorized shares of capital stock of NiSource or the total number of authorized shares of preferred stock. We voluntarily delisted the preferred stock from the New York Stock Exchange in March 2024.

Equity Units. In December 2023, we issued 33,898,837 shares of our common stock under the purchase contract component of the Corporate Units. As of December 2023, each holder of Corporate Units was deemed to have automatically delivered to us the related Series C Mandatory Convertible Preferred Stock that were components of the Corporate Units in full satisfaction of such holder's obligations under the related purchase contract, and all 862,500 shares of Series C Mandatory Convertible Preferred Stock were returned to the status of authorized but unissued preferred stock, par value of \$0.01 per share, without designation as to series. We voluntarily delisted the Corporate Units from the New York Stock Exchange in December 2023.

Refer to Note 5, "Earnings Per Share," for additional information regarding our treatment of the Equity Units for diluted EPS.

Noncontrolling Interest in Consolidated Subsidiaries. As of December 31, 2025 and 2024, NIPSCO and tax equity partners have completed their cash contributions into the Indiana Crossroads Wind, Rosewater, Indiana Crossroads Solar and Dunn's Bridge I JVs. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the respective tax equity partners in varying percentages by category and over the life of the partnership. The tax equity partner's contributions, net of these allocations, is represented as a noncontrolling interest within total equity on the Consolidated Balance Sheets. Refer to Note 4, "Noncontrolling Interests," for more information.

In December 2023, we consummated the closing of the NIPSCO Minority Interest Transaction and issued a 19.9% equity interest in NIPSCO Holdings II LLC to BIP in exchange for a capital contribution of \$2.16 billion in cash. Transaction costs and deferred tax impacts of \$54.7 million and \$63.5 million, respectively, were recorded during the period ending December 31, 2023. Refer to Note 4, "Noncontrolling Interests," Note 15, "Income Taxes," and Note 19, "Other Commitments and Contingencies - E. Other Matters," in the Notes to the Consolidated Financial Statements for more information on this transaction.

In October 2025, NiSource issued a 19.9% direct equity interest in NiSource's wholly-owned subsidiary Generation Holdings II to BIP Orion Holdco L.P. and BIP Orion Holdco II L.P., affiliates of Blackstone (collectively, "Blackstone Investor"), in exchange for \$35.2 million. In October 2025, simultaneously with issuance of the 19.9% equity interest in Generation Holdings II, Blackstone Investor, Generation Holdings I, Generation Holdings II and NiSource entered into Generation Holdings II LLC Agreement. Refer to Note 4, "Noncontrolling Interests," and Note 19, "Other Commitments and Contingencies - E. Other Matters," for more information.

7. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program and accounts receivable transfer programs. Each of these borrowing sources is described further below.

Revolving Credit Facility. We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, the issuance of letters of credit and also for general corporate purposes. Our revolving credit facility has a facility limit of \$2.50 billion and is comprised of a syndicate of banks. In December 2025, we extended the termination date of our revolving credit facility to December 2030 and increased our facility limit from \$1.85 billion to \$2.50 billion. At December 31, 2025 and 2024, we had no outstanding borrowings under this facility.

Commercial Paper Program. In February 2024, we increased our program limit from \$1.50 billion to \$1.85 billion. We had \$736.0 million and \$604.6 million of commercial paper outstanding with weighted-average interest rates of 3.92% and 4.73% as of December 31, 2025 and 2024, respectively.

Accounts Receivable Transfer Programs. Columbia of Ohio, NIPSCO, and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through consolidated special purpose entities. The three agreements expire between May 2026 and October 2026 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2025, the maximum amount we could borrow related to our accounts receivable programs is \$175.0 million.

We had no short-term borrowings related to the securitization transactions as of December 31, 2025 and 2024, respectively.

For the year ended December 31, 2025 and 2024, zero and \$337.6 million, respectively, was recorded as cash flows used for financing activities related to the change in short-term borrowings due to securitization transactions. For the accounts receivable transfer programs, we pay used facility fees for amounts borrowed, unused commitment fees for amounts not borrowed and upfront renewal fees. Fees associated with the securitization transactions were \$1.4 million, \$1.5 million, and \$2.7 million for the years ended December 31, 2025, 2024 and 2023, respectively. Columbia of Ohio, NIPSCO and Columbia of Pennsylvania remain responsible for collecting the receivables securitized, and the receivables cannot be transferred to another party. Refer to Note 23, "Interest Expense, Net," for additional information on securitization transaction fees.

Items listed above are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

8. Long-Term Debt

Our long-term debt as of December 31, 2025 and 2024 is as follows:

Long-term debt type	Maturity as of December 31, 2025	Weighted average interest rate (%)	Outstanding balance as of December 31, (in millions)	
			2025	2024
Senior notes:				
NiSource	August 2025	0.950 %	\$ —	\$ 1,250.0
NiSource	May 2027	3.490 %	1,000.0	1,000.0
NiSource	December 2027	6.780 %	3.0	3.0
NiSource	March 2028	5.250 %	1,050.0	1,050.0
NiSource	July 2029	5.200 %	600.0	600.0
NiSource	September 2029	2.950 %	750.0	750.0
NiSource	May 2030	3.600 %	1,000.0	1,000.0
NiSource	February 2031	1.700 %	750.0	750.0
NiSource	June 2033	5.400 %	450.0	450.0
NiSource	April 2034	5.350 %	650.0	650.0
NiSource	July 2035	5.350 %	900.0	—
NiSource	December 2040	6.250 %	152.6	152.6
NiSource	June 2041	5.950 %	347.4	347.4
NiSource	February 2042	5.800 %	250.0	250.0
NiSource	February 2043	5.250 %	500.0	500.0
NiSource	February 2044	4.800 %	750.0	750.0
NiSource	February 2045	5.650 %	500.0	500.0
NiSource	May 2047	4.375 %	1,000.0	1,000.0
NiSource	March 2048	3.950 %	750.0	750.0
NiSource	June 2052	5.000 %	350.0	350.0
NiSource	April 2055	5.850 %	1,500.0	—
Total senior notes			\$ 13,253.0	\$ 12,103.0
Junior subordinated notes:				
NiSource	November 2054	6.950 %	\$ 500.0	\$ 500.0
NiSource	March 2055	6.375 %	500.0	500.0
NiSource	July 2056	5.750 %	1,000.0	—
Total junior subordinated notes			\$ 2,000.0	\$ 1,000.0
Medium term notes:				
NiSource	May 2027	7.990 %	\$ 29.0	\$ 29.0
NIPSCO	June 2027 to August 2027	7.644 %	58.0	58.0
Columbia of Massachusetts	December 2025	6.430 %	—	10.0
Columbia of Massachusetts	February 2028	6.260 %	5.0	5.0
Total medium term notes			\$ 92.0	\$ 102.0
Finance leases:				
NiSource Corporate Services	January 2026 to September 2027	4.350 %	\$ 5.0	\$ 14.6
NIPSCO	December 2027 to December 2063	5.480 %	165.5	124.3
Columbia of Ohio	December 2035 to March 2052	6.110 %	81.7	85.6
Columbia of Virginia	July 2029 to November 2039	5.620 %	16.2	15.2
Columbia of Kentucky	May 2027	5.360 %	0.1	0.1
Columbia of Pennsylvania	March 2030 to May 2035	4.430 %	5.5	6.4
Total finance leases			\$ 274.0	\$ 246.2
Less: Unamortized issuance costs and discounts			(141.5)	(95.5)
Less: Current portion of long term debt			(19.7)	(1,281.2)
Total Long-Term Debt			\$ 15,457.8	\$ 12,074.5

Details of our 2025 long-term debt activity are summarized below:

- In March 2025, we completed the issuance and sale of \$750.0 million of 5.850% senior unsecured notes maturing in 2055, which resulted in approximately \$739.6 million of net proceeds after discount and debt issuance costs.
- In June 2025, we completed the issuance and sale of an additional \$750.0 million of 5.850% senior unsecured notes maturing in 2055 (the "2055 Notes"). The terms of the 2055 Notes, other than the issue date and the price to the public, are identical to the terms of, and constitute a reopening of, our 5.850% senior unsecured notes maturing in 2055 issued in March, 2025. With the incremental issuance, we now have \$1.5 billion of 5.850% senior unsecured notes maturing in 2055. In June 2025, we also completed the issuance and sale of \$900.0 million of 5.350% senior unsecured notes maturing in 2035 (the "2035 Notes"). The issuances of the 2055 Notes and the 2035 Notes in June, 2025 resulted in approximately \$1.616 billion of total net proceeds after discount and debt issuance costs.
- In August 2025, we repaid \$1,250.0 million of 0.95% senior unsecured notes at maturity.
- In November 2025, we completed the issuance and sale of \$1.0 billion of 5.750% fixed-to-fixed reset rate junior subordinated notes maturing in 2056, which resulted in approximately \$984.3 million of net proceeds after debt issuance costs. The subordinated notes bear interest (i) from and including November 2025 to, but excluding, July 2031 at a rate of 5.75% per annum and (ii) from and including July 2031, during each five-year reset period at a rate per annum equal to the five-year U.S. treasury rate (determined as described in the prospectus supplement filed with the SEC in November 2025) as of the then most recent reset interest determination date plus a spread of 2.035%, to be reset on each reset date; provided that the interest rate during any reset period will not reset below 5.750% per annum. At our option, we may redeem some or all of the subordinated notes during specified periods, and upon the occurrence of certain ratings or tax events, all as described in the prospectus supplement. In accordance with terms of the subordinated notes, we have the right, from time to time, to defer the payment of interest on the outstanding subordinated notes on one or more occasions for up to ten consecutive years. In the event that we were to exercise such right to defer interest on the subordinated notes, we would not be able to pay cash dividends on the common stock during the periods in which such payments were deferred.
- In December 2025, Columbia of Massachusetts repaid \$10.0 million of 6.430% medium term notes at maturity.

Details of our 2024 long-term debt activity are summarized below:

- In March 2024, we completed the issuance and sale of \$650.0 million of 5.350% senior unsecured notes maturing in 2034, which resulted in approximately \$642.6 million of net proceeds after discount and debt issuance costs.
- In May 2024, we completed the issuance and sale of \$500.0 million of 6.950% fixed-to-fixed reset rate junior subordinated notes maturing in 2054, which resulted in approximately \$493.4 million of net proceeds after debt issuance costs. The subordinated notes bear interest (i) from and including May 2024 to, but excluding, November 2029 at a rate of 6.950% per annum and (ii) from and including November 2029, during each five-year reset period at a rate per annum equal to the five-year U.S. treasury rate (determined as described in the prospectus supplement filed with the SEC in May 2024) as of the then most recent reset interest determination date plus a spread of 2.451%, to be reset on each reset date. At our option, we may redeem some or all of the subordinated notes during specified periods, and upon the occurrence of certain ratings or tax events, all as described in the prospectus supplement. In accordance with terms of the subordinated notes, we have the right, from time to time, to defer the payment of interest on the outstanding subordinated notes on one or more occasions for up to ten consecutive years. In the event that we were to exercise such right to defer interest on the subordinated notes, we would not be able to pay cash dividends on the common stock during the periods in which such payments were deferred.
- In June 2024, we completed the issuance and sale of \$600.0 million of 5.200% senior unsecured notes maturing in 2029, which resulted in approximately \$593.7 million of net proceeds after discount and debt issuance costs.
- In September 2024, we completed the issuance and sale of \$500.0 million of 6.375% fixed-to-fixed reset rate junior subordinated notes maturing in 2055, which resulted in approximately \$493.6 million of net proceeds after debt issuance costs. The subordinated notes bear interest (i) from and including September 2024 to, but excluding, March 2035 at a rate of 6.375% per annum and (ii) from and including March 2035, during each five-year reset period at a rate per annum equal to the five-year U.S. treasury rate (determined as described in the prospectus supplement filed with the SEC in September 2024) as of the then most recent reset interest determination date plus a spread of 2.527%,

to be reset on each reset date. At our option, we may redeem some or all of the subordinated notes during specified periods, and upon the occurrence of certain ratings or tax events, all as described in the prospectus supplement. In accordance with terms of the subordinated notes, we have the right, from time to time, to defer the payment of interest on the outstanding subordinated notes on one or more occasions for up to ten consecutive years. In the event that we were to exercise such right to defer interest on the subordinated notes, we would not be able to pay cash dividends on the common stock during the periods in which such payments were deferred.

See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2025.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2025, the ratio was 51.0%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to \$500 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 15% of our consolidated total assets as of the last day of our fiscal year then most recently ended for which financial statements have been delivered. Additionally, the revolving credit facility requires us to own directly or indirectly at least 70% of NIPSCO. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of \$100.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of \$5.0 million to \$50.0 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

9. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, <i>(in millions)</i>	2025	2024
Property, Plant and Equipment		
Gas distribution utility	\$ 21,509.4	\$ 20,007.2
Electric utility	11,420.7	8,666.8
Corporate	236.4	248.1
Construction work in process	1,700.7	2,084.7
JV renewable generation assets ⁽¹⁾	1,429.3	1,434.2
Non-utility and other	1,762.3	1,711.9
Total Property, Plant and Equipment	\$ 38,058.8	\$ 34,152.9
Accumulated Depreciation and Amortization		
Gas distribution utility	\$ (4,427.3)	\$ (4,166.8)
Electric utility	(2,987.0)	(2,707.8)
Corporate	(156.1)	(163.4)
JV renewable generation assets ⁽¹⁾	(156.3)	(110.4)
Non-utility and other	(1,643.9)	(1,550.6)
Total Accumulated Depreciation and Amortization	\$ (9,370.6)	\$ (8,699.0)
Net Property, Plant and Equipment	\$ 28,688.2	\$ 25,453.9

⁽¹⁾These JV renewable generation assets owned and operated by JVs between NIPSCO and unrelated tax equity partners represent Non-Utility Property, are depreciated straight-line over 30 years and are part of our NIPSCO Operations segment. Refer to Note 4, "Noncontrolling Interests," for additional information.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2025, 2024 and 2023 were as follows:

	2025	2024	2023
NIPSCO Operations	3.0 %	3.0 %	3.0 %
Columbia Operations	2.6 %	2.6 %	2.5 %

We recognized depreciation expense of \$1,008.9 million, \$820.4 million and \$756.9 million for the years ended 2025, 2024 and 2023, respectively. The 2025, 2024 and 2023, depreciation expense includes \$62.4 million, \$58.9 million, and \$12.5 million related to the regulatory deferral of income associated with our JVs. See Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for additional details.

Amortization of on-premises Software Costs. We amortized \$76.0 million, \$85.2 million and \$77.5 million in 2025, 2024 and 2023, respectively, related to software recorded as intangible assets. Our unamortized software balance was \$390.3 million and \$236.1 million at December 31, 2025 and 2024, respectively.

Amortization of Cloud Computing Costs. We amortized \$27.0 million, \$17.7 million and \$12.6 million in 2025, 2024 and 2023, respectively, related to cloud computing costs to "Operation and maintenance" expense. Our unamortized cloud computing balance was \$165.1 million and \$77.5 million at December 31, 2025 and 2024, respectively.

10. Goodwill

The following presents our goodwill balance allocated by segment as of December 31, 2025:

<i>(in millions)</i>	Columbia Operations	NIPSCO Operations	Total
Goodwill	\$ 1,468.1	\$ 17.8	\$ 1,485.9

For our annual goodwill impairment analysis performed as of May 1, 2025, we performed a qualitative "step 0" assessment and determined that it was more likely than not that the estimated fair value of a reporting unit substantially exceeded its carrying value of our reporting unit. For this test, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting unit as compared to its baseline May 1, 2024 "step 1" fair value measurement. There have been no impairments recorded during the periods presented.

11. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities (including our JV facilities), certain costs to retire pipeline, removal costs for certain underground storage tanks, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have an obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

During 2025, we continued to evaluate the applicability of revisions to the EPA rule for disposal of CCRs, which was announced in May 2024. As a result, during 2025, we recorded an increase of \$48.9 million based on initial assessments of estimated costs to comply with the EPA rule for certain sites. Additional costs will be recorded if they become probable and estimable. These costs are expected to be recoverable through existing and future depreciation rates. See Note 19, "Other Commitments and Contingencies - D. Environmental Matters," for additional information on the legacy CCR rule.

Changes in our liability for asset retirement obligations for the years 2025 and 2024 are presented in the table below:

<i>(in millions)</i>	2025	2024
Beginning Balance	\$ 783.2	\$ 553.0
Accretion recorded as a regulatory asset/liability	38.0	25.3
Additions	63.3	189.9
Settlements	(73.0)	(72.5)
Change in estimated cash flows	25.4	87.5
Ending Balance	\$ 836.9	\$ 783.2

Certain non-legal costs of removal not yet incurred but have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

12. Regulatory Matters

Regulatory Filings

Renewable generation filings. In February 2025, NIPSCO filed a petition with the IURC to modify its February 2023 order that approved a power purchase agreement related to Templeton and allow for NIPSCO to fully own Templeton. The IURC issued an order in September 2025 approving the filed petition.

NIPSCO Electric rate case filing. In February 2025, NIPSCO and certain intervening parties filed a Joint Stipulation and Settlement Agreement with the IURC. The IURC issued an order in June 2025, approving the Settlement Agreement without modification. New rates were implemented in multiple steps beginning in July 2025 and will continue with the final step no later than March 2026.

Columbia of Pennsylvania rate case filing. In December 2025, the Pennsylvania Public Utility Commission issued a final order accepting in part, and denying in part, Columbia's exceptions to the recommended decision issued by the Administrative Law Judges. The final order approved the continuation of a pilot residential Weather Normalization Adjustment with a few modifications (most notably increasing the percentage range in which weather normalization is applied from 3% to 5% and an increase to the residential fixed customer charge to \$20.15. Rates became effective in January 2026. Two parties have filed petitions for reconsideration on certain aspects of the final order and petitions for reconsideration are pending.

GenCo filing. In January 2025, GenCo, an indirect subsidiary of NiSource Inc., filed a declination of jurisdiction petition with the IURC related to the ownership, development, financing, construction and operation of generation facilities. This was an

administrative filing and is a step in NIPSCO's effort to set up a framework to accommodate megaload customers, including data centers. A settlement agreement among GenCo, NIPSCO, and a coalition of NIPSCO's largest industrial customers was approved by the IURC in September 2025. In October 2025, the Indiana Office of the Utility Consumer Counselor ("OUCC") filed a limited Request for Rehearing with the IURC and the OUCC filed a Notice of Appeal of the IURC order approving the GenCo settlement, which was immediately stayed by the Court of Appeals to allow the IURC process to be completed. In November 2025, the IURC issued an order granting the OUCC's limited request for rehearing, which was supported by NIPSCO and GenCo. In December 2025, all parties who originally appealed the IURC approval filed motions to dismiss their respective appeals.

NIPSCO Electric Special Contract and GenCo PPA filing. In November 2025, NIPSCO and GenCo filed an application with the IURC seeking approval of (i) a retail special contract for electric service between NIPSCO and ADS, (ii) a related power purchase agreement between NIPSCO and GenCo, and (iii) an alternative regulatory plan and associated accounting treatment. Testimony from the OUCC and intervenors was filed in January 2026. The OUCC and one other intervenor were generally supportive of approval of the special contract and GenCo PPA, while one intervenor sought certain modifications to the special contract. A hearing is scheduled for February 2026. An order is anticipated in the second quarter of 2026.

202(c) Emergency Order for R.M. Schahfer coal facility. In December 2025, before the planned retirement of the R.M. Schahfer coal facility, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring R.M. Schahfer to continue operating for 90 days, through March 23, 2026. The order stated that continued operation of R.M. Schahfer was required to meet an energy emergency across MISO's North and Central regions. Following receipt of the emergency order, NIPSCO filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. NIPSCO made two filings with the IURC related to the emergency order. The first filing is to confirm accounting treatment of the current electric rate order, and the second is a filing for recovery of federally mandated expenses related to the emergency order, which will be utilized in the event that any costs of complying with the emergency order fall outside of the MISO Tariff recovery. The Michigan City coal facility is scheduled to be retired by the end of 2028.

IURC Investigation. In November 2025, the IURC initiated an investigation into the accuracy of NIPSCO's gas meters. This investigation followed NIPSCO's disclosure of a latent issue with a small percentage of the meter indexes in NIPSCO's gas meters, which was discovered during roll-out of new AMI communications modules for gas meters. A procedural schedule has been established and a hearing is expected in July 2026.

Regulatory Assets and Liabilities. We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures when the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates will be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers. We assess the probability of collection for all of our regulatory assets each period. The offset to the regulatory liability associated with our renewable investments included in regulated rates is recorded in "Depreciation and amortization" on the Statements of Consolidated Income.

Regulatory assets were comprised of the following items:

At December 31, <i>(in millions)</i>	2025	2024
Regulatory Assets		
Unrecognized pension and other postretirement benefit costs (see Note 16)	\$ 433.1	\$ 485.3
Deferred pension and other postretirement benefit costs (see Note 16)	30.8	45.3
Environmental costs (see Note 19-D.)	42.0	42.8
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 15)	190.8	172.0
Under-recovered gas and fuel costs (see Note 1-J.)	41.3	82.3
Depreciation	218.4	214.9
Post-in-service carrying charges	287.2	280.8
Safety activity costs	200.6	203.7
DSM programs	13.4	17.8
Retired coal generating stations	552.1	617.0
Losses on commodity price risk programs (See Note 13)	10.1	6.5
Deferred property taxes	79.4	75.9
Renewable energy investments	130.7	81.3
WAM system filing	33.5	21.5
Customer assistance programs	17.3	24.4
Uncollected future cost of removal	102.5	—
Other	116.2	105.8
Total Regulatory Assets	\$ 2,499.4	\$ 2,477.3
Less: Current Portion	274.2	319.9
Total Noncurrent Regulatory Assets	\$ 2,225.2	\$ 2,157.4

Regulatory liabilities were comprised of the following items:

At December 31, <i>(in millions)</i>	2025	2024
Regulatory Liabilities		
Over-recovered gas and fuel costs (see Note 1-J.)	\$ 50.6	\$ 21.4
Cost of removal (see Note 11)	454.5	482.8
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 15)	869.3	827.0
Deferred pension and other postretirement benefit costs (see Note 16)	28.0	40.4
Gains on commodity price risk programs (See Note 13)	19.2	28.7
Customer assistance programs	10.6	9.4
Off-system sales sharing	21.8	21.4
Renewable energy investments (See Note 1-S. and Note 4)	139.4	77.0
Rate refunds	68.9	16.6
Other	111.1	57.0
Total Regulatory Liabilities	\$ 1,773.4	\$ 1,581.7
Less: Current Portion	260.1	150.5
Total Noncurrent Regulatory Liabilities	\$ 1,513.3	\$ 1,431.2

Regulatory assets, including under-recovered gas and fuel costs and depreciation, of approximately \$499.3 million and \$671.3 million as of December 31, 2025 and 2024, respectively, are not earning a return on investment. These costs are recovered over a remaining life of between 15 and 75 years.

Assets:

Unrecognized pension and other postretirement benefit costs. Represents the deferred other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs by certain subsidiaries that will ultimately be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between defined benefit plan expense recorded by certain subsidiaries due to regulatory orders and the corresponding expense that would otherwise be recorded in accordance with GAAP. This balance is driven by Columbia of Ohio deferrals.

Environmental costs. Includes certain recoverable costs related to gas plant sites, disposal sites or other sites onto which material may have migrated. The recovery of these costs is to be addressed in future base rates, billing riders or tracking mechanisms of certain of our subsidiaries.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel, as well as energy acquired through power purchase agreements, including NIPSCO's own renewable projects, and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals.

Safety activity costs. Represents the difference between costs incurred by certain of our subsidiaries in eligible safety programs in compliance with PHMSA regulations in excess of those being recovered in rates. The majority of this balance is driven by Columbia of Ohio.

DSM programs. Represents costs associated with Columbia Operations and NIPSCO Operations energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Retired coal generating stations. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018 and the net book value of Units 14 and 15 of R.M. Schahfer Generating Station retired in 2021. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates. The August 2023 NIPSCO electric rate case order extends the recovery of, and on, the net book value of the stations by the end of 2034 and implements a revenue credit for the retired units. The credit is based on the difference between the year-end value of Units 14 and 15 and the most recent value established in the last base rate case proceeding or credit compliance filing.

Losses on commodity price risk programs. Represents the unrealized losses related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices and these amounts are collected from customers through their inclusion in customer rates.

Deferred property taxes. Represents the deferral and under collection of property taxes in the rate making process for Columbia of Ohio and is driven by the IRP and CEP deferrals.

Renewable energy investments. Represents the regulatory deferral of renewable energy formation and developer costs primarily through deferred depreciation.

WAM system filing. Represents the deferral of certain costs, including depreciation and amortization incurred in connection with improvements to its information technology systems through the design, development, and implementation of a new WAM program for the scheduling, dispatch, and execution of work and the management of underlying assets.

Customer Assistance Programs. Represents the difference between the eligible customer assistance program costs and collections, which will be collected from customers.

Uncollected Future Cost of Removal. Represents asset removal costs not yet recovered.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel, as well as energy acquired through power purchase agreements, including NIPSCO's own renewable projects and, the recovery of such costs in revenues and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal for utility assets that have been collected through depreciation rates for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2025 and federal tax credits generated by Cavalry, Dunn's Bridge II, Fairbanks, and Gibson solar facilities that are passed back to customers. For discussion of the regulatory impact of the NIPSCO Minority Interest Transaction on deferred taxes, see Note 15, "Income Taxes," for additional details.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred by certain subsidiaries.

Gains on commodity price risk programs. Represents the unrealized gains related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices, and these amounts are passed back to customers through their inclusion in customer rates.

Customer Assistance Programs. Represents the difference between the eligible customer assistance program costs and collections, which will be refunded to customers.

Renewable energy investments. Represents the regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The offset to the regulatory liability associated with our renewable investments is recorded in "Depreciation expense" on the Statements of Consolidated Comprehensive Income. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," Note 4, "Noncontrolling Interests," and Note 9, "Property, Plant and Equipment," for additional information.

Rate Refunds. Represents supplier refunds received by the company that are owed to customers and will be remitted and amounts that are being collected in rates subject to refund.

Off System Sales Sharing. Represents amounts to be passed back to the customers as a result of Off System sales that is shared between the company and the customer.

13. Risk Management Activities

We are exposed to certain risks related to our ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to limit volatility in the price of natural gas, and manage interest rate exposure.

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

(in millions)	December 31, 2025		December 31, 2024	
	Assets	Liabilities	Assets	Liabilities
Current⁽¹⁾				
Derivatives not designated as hedging instruments	\$ 9.7	\$ 2.1	\$ 9.1	\$ 2.3
Total	\$ 9.7	\$ 2.1	\$ 9.1	\$ 2.3
Noncurrent⁽²⁾				
Derivatives not designated as hedging instruments	\$ 9.1	\$ 3.8	\$ 17.9	\$ 1.2
Total	\$ 9.1	\$ 3.8	\$ 17.9	\$ 1.2

⁽¹⁾ Current assets and liabilities are presented in "Prepayments and other" and "Other accruals", respectively, on the Consolidated Balance Sheets.

⁽²⁾ Noncurrent assets and liabilities are presented in "Deferred charges and other" and "Other noncurrent liabilities and deferred credits", respectively, on the Consolidated Balance Sheets.

Our derivative instruments are subject to enforceable master netting arrangements or similar agreements. No collateral was either received or posted related to our outstanding derivative positions at December 31, 2025 and 2024. If the above gross asset and liability positions were presented net of amounts owed or receivable from counterparties, we would report a net asset position of \$12.9 million and \$23.5 million at December 31, 2025 and 2024, respectively.

Derivatives Not Designated as Hedging Instruments

Commodity price risk management. We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts. As of December 31, 2025 and 2024, we had 83.7 MMDth and 77.8 MMDth, respectively, of net energy derivative volumes outstanding related to our natural gas hedges.

NIPSCO has received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments and is limited to 20% of NIPSCO's average annual GCA purchase volume. As of December 31, 2025, the remaining terms of these instruments range from one to three years. Likewise, Columbia of Pennsylvania has received approval for a 24-month rolling hedge program that will continue in perpetuity. The program is designed to financially hedge approximately 20% of the customer's annual demand. Under both programs all gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through the relevant cost recovery mechanism.

Derivatives Designated as Hedging Instruments

Interest rate risk management. As of December 31, 2025 and 2024, we had no active interest rate swap positions. We have recorded the overall net loss related to previously settled interest rate swaps in AOCI. The gain or loss associated with each previously settled interest rate swap is amortized in interest expense over the term of each corresponding debt issuance. These amounts were immaterial for the years ended December 31, 2025, 2024 and 2023 and are recorded in "Interest expense, net" on the Condensed Statements of Consolidated Income. Amounts expected to be reclassified to earnings during the next twelve months are immaterial. See Note 20, "Accumulated Other Comprehensive Loss," for additional information.

14. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements

The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2025 and December 31, 2024. As of December 31, 2025 and December 31, 2024, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

Recurring Fair Value Measurements December 31, 2025 (in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2025
Assets				
Risk management assets	\$ —	\$ 18.8	\$ —	\$ 18.8
Available-for-sale debt securities	—	146.1	—	146.1
Equity Securities ⁽¹⁾⁽²⁾	8.5	—	—	8.5
Total	\$ 8.5	\$ 164.9	\$ —	\$ 173.4
Liabilities				
Risk management liabilities	\$ —	\$ 5.9	\$ —	\$ 5.9
Total	\$ —	\$ 5.9	\$ —	\$ 5.9

⁽¹⁾ Equity securities are in a high dividend equity fund and are valued using market prices in active markets. Level 1 instrument valuations are obtained from real-time quotes for transactions in active exchange markets involving identical assets. Equity securities are presented in "Other Investments" on the Consolidated Balance Sheets.

⁽²⁾ As of December 31, 2025, the investment cost of equity securities measured at fair value was \$7.9 million, gross unrealized gains were \$0.7 million, and the fair value was \$8.5 million.

Recurring Fair Value Measurements December 31, 2024 (in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2024
Assets				
U.S. Treasury debt securities ⁽¹⁾	\$ 80.1	\$ —	\$ —	\$ 80.1
Risk management assets	—	27.0	—	27.0
Available-for-sale debt securities	—	86.7	—	86.7
Total	\$ 80.1	\$ 113.7	\$ —	\$ 193.8
Liabilities				
Risk management liabilities	\$ —	\$ 3.5	\$ —	\$ 3.5
Total	\$ —	\$ 3.5	\$ —	\$ 3.5

⁽¹⁾ Treasury bills are presented in "Cash and cash equivalents" and "Restricted cash" on the Consolidated Balance Sheets.

Level 1- When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. These financial assets and liabilities are deemed to be cleared and settled daily by NYMEX as the related cash collateral is posted with the exchange. As a result of this exchange rule, NYMEX derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes, and are presented in Level 1 net of posted cash; however, the derivatives remain outstanding and are subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

Level 2- Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, and options. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2.

Level 3- Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3.

Risk Management Assets and Liabilities. Risk management assets and liabilities include exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts. NIPSCO and Columbia of Pennsylvania have entered into long-term forward natural gas purchase instruments to lock in a fixed price for natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information, see Note 13, "Risk Management Activities."

Available-for-Sale Debt Securities. Available-for-sale debt securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2.

Our available-for-sale debt securities impairments are recognized periodically using an allowance approach. At each reporting date, we utilize a quantitative and qualitative review process to assess the impairment of available-for-sale debt securities at the individual security level. For securities in a loss position, we evaluate our intent to sell or whether it is more-likely-than-not that we will be required to sell the security prior to the recovery of its amortized cost. If either criteria is met, the loss is recognized in earnings immediately, with the offsetting entry to the carrying value of the security. If both criteria are not met, we perform an analysis to determine whether the unrealized loss is related to credit factors. The analysis focuses on a variety of factors that include, but are not limited to, downgrade on ratings of the security, defaults in the current reporting period or projected defaults in the future, the security's yield spread over treasuries, and other relevant market data. If the unrealized loss is not related to credit factors, it is included in other comprehensive income. If the unrealized loss is related to credit factors, the loss is recognized as credit loss expense in earnings during the period, with an offsetting entry to the allowance for credit losses. The amount of the credit loss recorded to the allowance account is limited by the amount at which the security's fair value is less than its amortized cost basis. If certain amounts recorded in the allowance for credit losses are deemed uncollectible, the allowance on the uncollectible portion will be charged off, with an offsetting entry to the carrying value of the security. Subsequent improvements to the estimated credit losses of available-for-sale debt securities will be recognized immediately in earnings. Continuous credit monitoring and portfolio credit balancing mitigates our risk of credit losses on our available-for-sale debt securities.

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NI\$OURCE INC.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Notes to Consolidated Financial Statements

The amortized cost, gross unrealized gains and losses, allowance for credit losses, and fair value of available-for-sale securities at December 31, 2025 and 2024 were:

December 31, 2025 (in millions)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses ⁽¹⁾	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
U.S. Treasury debt securities	\$ 9.5	\$ —	\$ —	\$ —	9.5
Corporate/Other debt securities	136.3	2.4	(2.1)	—	136.6
Total	\$ 145.8	\$ 2.4	\$ (2.1)	\$ —	146.1

December 31, 2024 (in millions)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses ⁽²⁾	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
Corporate/Other debt securities	91.9	0.5	(5.6)	(0.1)	86.7
Total	\$ 91.9	\$ 0.5	\$ (5.6)	\$ (0.1)	86.7

⁽¹⁾ Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is \$3.5 million and \$40.2 million, respectively at December 31, 2025.

⁽²⁾ Fair value of Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is \$70.1 million at December 31, 2024.

The cost of maturities sold is based upon specific identification. Net realized gains and losses on available-for-sale securities were \$(1.0) million for the twelve months ended December 31, 2025, and \$2.3 million for the twelve months ended December 31, 2024. At December 31, 2025, approximately \$9.8 million and \$4.0 million of Corporate/Other debt securities and U.S. Treasury debt securities, respectively, have maturities of less than a year.

Equity Investments. Investments measured at net asset value per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder. As of December 31, 2025, the Company holds \$17.9 million of equity investments measured at net asset value.

Non-recurring Fair Value Measurements

We measure the fair value of certain assets, including goodwill, on a non-recurring basis, typically when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. As of December 31, 2025, no non-recurring fair value adjustments have been made.

B. Other Fair Value Disclosures for Financial Instruments.

The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2025 and 2024, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, (in millions)	Carrying Amount 2025	Estimated Fair Value 2025	Carrying Amount 2024	Estimated Fair Value 2024
Long-term debt (including current portion)	\$ 15,477.5	\$ 14,975.3	\$ 13,355.7	\$ 12,505.2

15. Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws and associated regulations involves uncertainty as taxing authorities may interpret the laws differently.

NIPSCO's historical business activities through the closing of the NIPSCO Minority Interest Transaction in 2023 were included in the consolidated U.S. federal and certain state income tax returns of NiSource Inc. Prior to April 13, 2023, NIPSCO was treated as a taxable division of its corporate parent, NiSource Inc. Beginning on that date, NIPSCO became a division of NIPSCO Holdings I. In connection with the NIPSCO Minority Interest Transaction, NIPSCO Holdings I retained NIPSCO's income tax balances and 80.1% of the excess deferred income tax regulatory balances as described below. NIPSCO Holdings I's income tax balances are based on the difference between the financial statement amount and the tax basis of its investment in NIPSCO Holdings II.

Income Tax Expense. The components of income tax expense (benefit) were as follows:

Year Ended December 31, (in millions)	2025	2024	2023
Income Taxes			
Current			
Federal	\$ (30.4)	\$ (19.3)	\$ —
State	(1.6)	9.4	5.3
Total Current (Benefit) Expense	(32.0)	(9.9)	5.3
Deferred			
Federal			
Taxes before operating loss carryforwards and investment credits	189.2	105.9	49.7
Tax utilization expense of operating loss carryforwards	34.2	60.4	65.1
Investment tax credits	—	(0.1)	(2.1)
State	13.1	2.6	22.5
Total Deferred Expense	236.5	168.8	135.2
Deferred Investment Tax Credits	(0.7)	(0.8)	(1.0)
Income Taxes from Continuing Operations	\$ 203.8	\$ 158.1	\$ 139.5

We earn federal Investment Tax Credits ("ITC"s) and Production Tax Credits ("PTC"s) related to qualifying renewable energy projects. These credits are nonrefundable, can be utilized to offset income tax liabilities, and are transferable. We recognize the benefit of these credits within income tax expense (benefit) in the period the credits are generated.

During the periods ended December 31, 2025 and 2024, respectively, we elected to monetize certain transferable ITC/PTC credits through sales to unrelated third-party taxpayers. Accordingly, the cash proceeds received from the sale of the credits are reflected as an adjustment to income tax (benefit) expense. We recognized a current tax benefit associated with the monetization of these credits of \$19.3 million and \$18.8 million, for the years ended December 31, 2025, and 2024, respectively. These amounts offset current tax expense in the years received and a regulatory liability was established to pass back to customers over ten years, as ordered by the regulator.

In connection with the NIPSCO Minority Interest Transaction during 2023, NiSource recognized a \$63.5 million income tax benefit in additional paid in capital related to 19.9% of NIPSCO's excess deferred income taxes attributable to Blackstone's noncontrolling interest. This benefit does not impact NIPSCO's regulatory books or the excess deferred taxes that will benefit customers through lower future rates in accordance with applicable regulatory orders. See Note 4, "Noncontrolling Interests," for further discussion of the NIPSCO Minority Interest Transaction.

Statutory Rate Reconciliation. The following table provides a quantitative reconciliation of the reported income tax expense (benefit) from the statutory U.S. federal income tax rate to the Company's effective tax rate for each period presented.

Year Ended December 31, (in millions)	2025		2024		2023		
Book income before income taxes	\$	1,216.4	\$	1,002.8	\$	813.9	
Tax expense (benefit) at statutory federal income tax rate		255.4	21.0 %	210.6	21.0 %	170.8	21.0 %
State and local income taxes, net of federal income tax effect		4.9	0.4	11.7	1.2	13.7	1.7
Tax Credits							
Investment tax credit		(32.4)	(2.7)	(14.5)	(1.5)	(2.1)	(0.3)
Production tax credit		(40.5)	(3.3)	(5.8)	(0.6)	(0.3)	—
Other		(3.1)	(0.3)	(3.0)	(0.3)	(1.5)	(0.2)
Regulatory Adjustments							
ITC / PTC		68.2	5.6	20.0	2.0	—	—
Amortization of Excess Deferred Income Taxes		(30.2)	(2.5)	(31.2)	(3.1)	(39.2)	(4.8)
AFUDC equity		(5.5)	(0.4)	(12.5)	(1.2)	(5.3)	(0.7)
Changes in Valuation Allowances		8.4	0.7	—	—	—	—
Nontaxable or Nondeductible Items							
Noncontrolling interests		(18.2)	(1.5)	(27.3)	(2.7)	—	—
Other		1.2	0.1	7.6	0.8	7.8	0.9
Other adjustments		(4.4)	(0.3)	2.5	0.2	(4.4)	(0.5)
Income Taxes	\$	203.8	16.8 %	\$ 158.1	15.8 %	\$ 139.5	17.1 %

For the year ended December 31, 2025, the state and local income tax reconciling item of \$4.9 million represents the tax effect of income primarily in Virginia, which accounted for more than 50 percent of the company's state and local tax liability.

The increase in tax expense of \$45.7 million in 2025 versus 2024 was primarily due to higher pre-tax income, the establishment of a valuation allowance on deferred tax assets related to disallowed §163(j) interest carryforwards, lower non-controlling interest and lower AFUDC equity, partially offset by lower state taxes and higher federal investment and production credits generated by Dunns Bridge II Solar and Storage facility, Cavalry Solar, Fairbanks Solar, and Gibson Solar that are offset in a regulatory liability to pass back to customers in future periods.

The increase in the ITC / PTC regulatory adjustment in 2025 versus 2024 was primarily due to the regulatory liability established for the investment and production tax credits generated in 2025, net of the \$4.6 million pass back to customers of prior period federal tax credits.

The increase in tax expense of \$18.6 million in 2024 versus 2023 was primarily due to higher pre-tax income, partially offset by the tax effect of non-controlling interest, and higher federal tax credits generated by the Cavalry solar and storage facility that are offset in a regulatory liability to pass back to customers in future periods.

The increase in the ITC / PTC regulatory adjustment in 2024 versus 2023 was primarily due to the regulatory liability established for the Cavalry tax credits generated in 2024.

Cash Taxes Paid Disclosure. In accordance with ASU 2023-09, the following table provides cash taxes paid for each period presented, which represents the actual cash payments made for income taxes to federal and state authorities by jurisdiction and differs from the income tax expense recognized for financial reporting purposes due to deferred taxes, credits, and other reconciling items.

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Year Ended December 31, (in millions)	2025	2024	2023
Jurisdiction			
Federal	\$ 2.5	\$ —	\$ —
Pennsylvania	(0.2)	3.0	4.0
Virginia	—	1.2	5.4
Ohio local	0.7	—	—
Other	0.3	0.1	—
Total Cash Taxes Paid	\$ 3.3	\$ 4.3	\$ 9.4

The state component for 2025 and prior years primarily relates to Pennsylvania, Virginia and local Ohio taxes, accounting for greater than 50 percent of the total state tax payments.

Net Deferred Income Tax Liability Components. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liabilities were as follows:

At December 31, (in millions)	2025	2024
Deferred tax liabilities		
Accelerated depreciation and other property differences	\$ 1,552.0	\$ 1,419.4
Partnership basis differences	1,431.1	1,328.6
Other regulatory assets	210.3	210.1
Total Deferred Tax Liabilities	3,193.4	2,958.1
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	185.1	170.4
Pension and other postretirement/postemployment benefits	32.0	58.8
Net operating loss carryforwards	326.0	369.4
Environmental liabilities	10.3	12.2
Other accrued liabilities	49.6	43.4
Disallowed §163(j) interest expense carryforward	8.4	—
General business credits	77.3	20.5
Other, net	19.4	8.2
Total Deferred Tax Assets	708.1	682.9
Valuation Allowance	(14.8)	(6.4)
Net Deferred Tax Assets	693.3	676.5
Net Deferred Tax Liabilities	\$ 2,500.1	\$ 2,281.6

Deferred tax assets include amounts for disallowed §163(j) interest expense carryforward; during the period, we recorded a valuation allowance on these amounts in accordance with realizability requirements, and corresponds to the unfavorable item presented in the rate reconciliation.

On April 14, 2023, the IRS issued Revenue Procedure 2023-15 which provides a safe harbor method of accounting that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve linear property and non-linear natural gas transmission and distribution property must be capitalized as improvements or are allowable as deductions. On June 3, 2024, the IRS extended the favorable rules to a Year 2 adoption period. The Company filed a method change with its 2024 consolidated tax return filing to elect this change in tax accounting method under the cutoff method.

In connection with the NIPSCO Minority Interest Transaction, NIPSCO's deferred taxes were removed from its GAAP books and were reconstituted as deferred taxes on the outside basis difference of NiSource's investment in NIPSCO Holdings II. These deferred taxes are reflected as partnership basis differences above.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Notes to Consolidated Financial Statements

NiSource has the following deductible loss and credit carryforwards:

At December 31, 2025 (in millions)	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
Federal losses	\$ 1,192.0	\$ 250.3	\$ —	Indefinite
Federal investment tax credits	—	31.0	—	2043-2045
Federal production tax credits	—	23.4	—	2040-2045
Federal other credit	—	22.9	—	2029-2045
Federal disallowed interest expense carryforward	—	8.4	(8.4)	Indefinite
State losses	1,867.1	75.4	(6.4)	2029-2045
Total		\$ 411.4	\$ (14.8)	

We believe it is not more likely than not that the Federal §163(j) disallowed interest expense carryforward and a portion of the benefit from certain state net operating loss carryforwards will be realized. We have recorded a valuation allowance of \$8.4 million on the deferred tax asset related to the Federal §163(j) interest expense carryforward and \$6.4 million related to Massachusetts Net Operating Losses reflected in table presented above.

Unrecognized Tax Benefits. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

At December, (in millions)	2025	2024	2023
Opening Balance	\$ 21.7	\$ 21.7	\$ 21.7
Gross decreases - tax positions in prior period	—	—	—
Gross increases - current period tax positions	—	—	—
Ending Balance	\$ 21.7	\$ 21.7	\$ 21.7
Offset for net operating loss carryforwards	(21.7)	(21.7)	(21.7)
Balance, Less Net Operating Loss Carryforwards	\$ —	\$ —	\$ —

We are subject to income taxation in the United States and various state jurisdictions, primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP, which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2025, tax years through 2023 have been audited and are closed to further assessment. NiSource has not yet received a final acceptance letter from the IRS for its 2024 return. However, no adjustments are expected.

The statute of limitations in each of the state jurisdictions in which we operate remains open between 3-4 years from the date the state income tax returns are filed. As of December 31, 2025, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

NiSource is obligated to report adjustments resulting from IRS audits or settlements to state taxing authorities. In addition, if NiSource utilizes net operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

16. Pension and Other Postemployment Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees' compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. Certain employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans' Asset Management. The Board has delegated oversight of the pension and other postretirement benefit plans' assets to the NiSource Benefits Committee (the "Committee"). The Committee has adopted investment policy statements for the pension and other postretirement benefit plans' assets. For the pension plans, we employ a liability-driven investing strategy. A total return approach is utilized for some of the other postretirement benefit plans' assets. A mix of diversified investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. The investment portfolio includes U.S. and non-U.S. equities, real estate, long-term and intermediate-term fixed income and alternative investments. Risk tolerance is established through careful consideration of plan liabilities, funded status, and asset class volatility. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

In determining the expected long-term rate of return on plan assets, historical markets are studied, relationships between equities and fixed income are analyzed and current market factors, such as inflation and interest rates are evaluated with consideration of diversification and rebalancing. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding long-term capital market assumptions for each asset class. The pension plans' investment policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans' increase.

As of December 31, 2025 and December 31, 2024, the acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

December 31, 2025 Asset Category	Defined Benefit Pension Plan		Postretirement Benefit Plan	
	Minimum	Maximum	Minimum	Maximum
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

December 31, 2024 Asset Category	Defined Benefit Pension Plan		Postretirement Benefit Plan	
	Minimum	Maximum	Minimum	Maximum
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

The actual Pension Plan and Postretirement Plan Asset Mix at December 31, 2025 and December 31, 2024 are as follows:

Asset Class (in millions)	Defined Benefit Pension Assets ⁽¹⁾	December 31, 2025	Postretirement Benefit Plan Assets	December 31, 2025
	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	\$ 270.0	20.2 %	\$ 105.4	40.8 %
International Equities	137.5	10.3 %	48.8	18.9 %
Fixed Income	869.0	64.9 %	99.2	38.5 %
Cash/Other	61.9	4.6 %	4.6	1.8 %
Total	\$ 1,338.4	100.0 %	\$ 258.0	100.0 %

⁽¹⁾Total includes accrued dividends and pending trades with brokers.

Asset Class (in millions)	Defined Benefit Pension Assets ⁽¹⁾	December 31, 2024	Postretirement Benefit Plan Assets ⁽¹⁾	December 31, 2024
	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	\$ 258.9	19.4 %	\$ 99.6	40.9 %
International Equities	122.5	9.2 %	40.7	16.7 %
Fixed Income	891.2	66.7 %	96.5	39.6 %
Real Estate	4.0	0.3 %	—	—
Cash/Other	59.8	4.4 %	6.7	2.8 %
Total	\$ 1,336.4	100.0 %	\$ 243.5	100.0 %

⁽¹⁾Total includes accrued dividends and pending trades with brokers.

The categorization of investments into the asset classes in the tables above are based on definitions established by the Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the pension and other postretirement benefits investment assets at fair value as of December 31, 2025 and 2024. Assets are classified in their entirety based on the observability of inputs used in determining the fair value measurement. There were no material investment assets in the pension and other postretirement benefits trusts classified within Level 3 for the years ended December 31, 2025 and 2024.

We use the following valuation techniques to determine fair value. For the year ended December 31, 2025, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

Level 1 Measurements

Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost, which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements

Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements

Investments with unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities are classified as level 3 investments.

Not Classified

Commingled funds, private equity limited partnerships and real estate partnerships are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. Commingled funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers. Private equity funds invest capital in non-public companies and real estate funds invest in commercial and distressed real estate directly or through related debt instruments. The fair value of these investments is determined by reference to the funds' underlying assets.

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NI SOURCE INC.
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)
Notes to Consolidated Financial Statements

Fair Value Measurements at December 31, 2025:

<i>(in millions)</i>	December 31, 2025	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	\$ 0.5	\$ 0.5	\$ —	\$ —
Fixed income securities				
Government	197.1	—	197.1	—
Corporate	471.5	—	471.5	—
Mortgages/ Asset Backed Securities	3.9	—	3.9	—
Other fixed income	0.1	—	0.1	—
Derivatives				
Assets	0.6	—	0.6	—
Mutual Funds				
U.S. multi-strategy	53.9	53.9	—	—
International equities	34.0	34.0	—	—
Private equity limited partnerships ⁽¹⁾				
U.S. multi-strategy ⁽²⁾	2.4	—	—	—
International multi-strategy ⁽³⁾	0.2	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate ⁽¹⁾	—	—	—	—
Commingled funds ⁽¹⁾				
Short-term money markets	50.1	—	—	—
U.S. equities	216.1	—	—	—
International equities	103.6	—	—	—
Fixed income	196.5	—	—	—
Pension plan assets subtotal	\$ 1,330.6	\$ 88.4	\$ 673.2	\$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	92.4	92.4	—	—
International equities	16.8	16.8	—	—
Fixed income	99.2	99.2	—	—
Commingled funds ⁽¹⁾				
Short-term money markets	4.6	—	—	—
U.S. equities	13.0	—	—	—
International equities	32.1	—	—	—
Other postretirement benefit plan assets subtotal	\$ 258.1	\$ 208.4	\$ —	\$ —
Due to brokers, net ⁽⁴⁾	(0.6)	—	(0.6)	—
Accrued income/dividends	8.3	8.3	—	—
Total pension and other postretirement benefit plan assets	\$ 1,596.4	\$ 305.1	\$ 672.6	\$ —

⁽¹⁾This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.

⁽²⁾This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.

⁽³⁾This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.

⁽⁴⁾This class represents pending trades with brokers.

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The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2025:

<i>(in millions)</i>	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Commingled Funds				
Short-term money markets	\$ 54.7	\$ —	Daily	1 day
U.S. equities	229.1	—	Daily	1 day - 10 days
International equities	135.7	—	Monthly	1 day-10 days
Fixed income	196.5	—	Daily	2 days
Private Equity and Real Estate Limited Partnerships ⁽¹⁾	2.7	9.3	N/A	N/A
Total	\$ 618.7	\$ 9.3		

⁽¹⁾Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

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NI SOURCE INC.
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)
Notes to Consolidated Financial Statements
Fair Value Measurements at December 31, 2024:

<i>(in millions)</i>	December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	\$ 1.2	\$ 1.1	\$ 0.1	\$ —
Fixed income securities				
Government	186.8	—	186.8	—
Corporate	486.6	—	486.6	—
Mortgages/Asset backed securities	3.6	—	3.6	—
Mutual Funds				
U.S. multi-strategy	56.1	56.1	—	—
International equities	57.2	57.2	—	—
Private equity limited partnerships⁽¹⁾				
U.S. multi-strategy ⁽²⁾	3.1	—	—	—
International multi-strategy ⁽³⁾	0.8	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate ⁽¹⁾	4.0	—	—	—
Commingled funds⁽¹⁾				
Short-term money markets	45.9	—	—	—
U.S. equities	202.8	—	—	—
International equities	65.3	—	—	—
Fixed income	214.1	—	—	—
Pension plan assets subtotal	\$ 1,327.6	\$ 114.4	\$ 677.1	\$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	87.4	87.4	—	—
International equities	16.5	16.5	—	—
Fixed income	96.5	96.5	—	—
Commingled funds⁽¹⁾				
Short-term money markets	6.7	—	—	—
U.S. equities	12.2	—	—	—
International equities	24.2	—	—	—
Other postretirement benefit plan assets subtotal	\$ 243.5	\$ 200.4	\$ —	\$ —
Due to brokers, net ⁽⁴⁾	(0.1)	—	(0.1)	—
Accrued income/dividends	8.9	8.9	—	—
Total pension and other postretirement benefit plan assets	\$ 1,579.9	\$ 323.7	\$ 677.0	\$ —

⁽¹⁾This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.

⁽²⁾This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.

⁽³⁾This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.

⁽⁴⁾This class represents pending trades with brokers.

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The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2024:

<i>(in millions)</i>	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	\$ 52.6	Daily	1 day
U.S. equities	215.0	Daily	1 day -5 days
International equities	89.5	Monthly	10 days - 30 days
Fixed income	214.1	Daily	3 days
Private Equity and Real Estate Limited Partnerships ⁽¹⁾	8.0	N/A	N/A
Total	\$ 579.2		

⁽¹⁾Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

<i>(in millions)</i>	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Change in projected benefit obligation⁽¹⁾				
Benefit obligation at beginning of year	\$ 1,287.4	\$ 1,401.8	\$ 436.3	\$ 468.8
Service cost	19.7	21.9	4.0	5.0
Interest cost	64.1	64.9	21.6	22.0
Plan participants' contributions	—	—	4.0	3.6
Plan amendments	—	—	(30.3)	—
Actuarial loss (gain) ⁽²⁾	34.8	(64.8)	(1.8)	(22.5)
Benefits paid	(135.2)	(136.4)	(39.0)	(40.7)
Estimated benefits paid by incurred subsidy	—	—	0.1	0.1
Projected benefit obligation at end of year	\$ 1,270.8	\$ 1,287.4	\$ 394.9	\$ 436.3
Change in plan assets				
Fair value of plan assets at beginning of year	\$ 1,336.5	\$ 1,426.8	\$ 243.2	\$ 236.5
Actual return on plan assets	132.8	43.7	28.7	20.0
Employer contributions	2.0	2.4	20.7	23.6
Plan participants' contributions	—	—	4.0	3.8
Benefits paid	(135.2)	(136.4)	(39.0)	(40.7)
Fair value of plan assets at end of year	\$ 1,336.1	\$ 1,336.5	\$ 257.6	\$ 243.2
Funded Status at end of year	\$ 65.3	\$ 49.1	\$ (137.3)	\$ (193.1)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	\$ 82.8	\$ 66.5	\$ 0.5	\$ —
Current liabilities	(2.6)	(2.3)	(1.0)	(1.0)
Noncurrent liabilities	(14.9)	(15.1)	(136.8)	(192.1)
Net amount recognized at end of year⁽³⁾	\$ 65.3	\$ 49.1	\$ (137.3)	\$ (193.1)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability⁽⁴⁾				
Unrecognized prior service credit	\$ 0.2	\$ 0.3	\$ (23.8)	\$ 3.8
Unrecognized actuarial loss	413.8	451.4	28.1	47.0
Net amount recognized at end of year	\$ 414.0	\$ 451.7	\$ 4.3	\$ 50.8

⁽¹⁾The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.

⁽²⁾The pension actuarial loss (gain) as of December 31, 2025 and December 31, 2024 was primarily driven by the decrease in discount rates interest rate movements and the increase in discount rates interest rate movements, respectively. The postretirement benefit actuarial (gain) as of December 31, 2025 and December 31, 2024 was primarily driven by claims experience changes in trend rates.

⁽³⁾We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.

⁽⁴⁾We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of \$433.1 million and zero, respectively, as of December 31, 2025, and \$485.3 million and zero, respectively, as of December 31, 2024 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was \$1,263.0 million and \$1,278.4 million as of December 31, 2025 and 2024, respectively. The accumulated benefit obligation at each date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

We are required to reflect the funded status of our pension and postretirement benefit plans on the Consolidated Balance Sheet. We present the noncurrent aggregate of all underfunded plans within "Accrued liability for postretirement and postemployment benefits." The portion of the amount by which the actuarial present value of benefits included in the projected benefit obligation exceeds the fair value of plan assets, payable in the next 12 months, is reflected in "Accrued compensation and other benefits." We present the aggregate of all overfunded plans within "Deferred charges and other."

For our pension plans as of December 31, 2025 and 2024, only our nonqualified plans were underfunded. These plans have no assets as they are not funded until benefits are paid. The following table sets forth the year end accumulated benefit obligation and projected benefit obligation for pension plans with a projected benefit obligation in excess of plan assets:

<i>(in millions)</i>	December 31,	
	2025	2024
Accumulated Benefit Obligation	\$ 17.5	\$ 17.4
Funded Status		
Projected Benefit Obligation	\$ 17.5	\$ 17.4
Funded Status of Underfunded Pension Plans at End of Year	\$ (17.5)	\$ (17.4)

The following table sets forth the year end accumulated benefit obligation, projected benefit obligation and fair value of plan assets for pension plans with plan assets in excess of the projected benefit obligation:

<i>(in millions)</i>	December 31,	
	2025	2024
Accumulated Benefit Obligation	\$ 1,245.5	\$ 1,261.0
Funded Status		
Fair Value of Plan Assets	\$ 1,336.1	\$ 1,336.4
Projected Benefit Obligation	1,253.3	1,269.9
Funded Status of Overfunded Pension Plans at End of Year	\$ 82.8	\$ 66.5

Our pension plans were overfunded, in aggregate, by \$65.3 million at December 31, 2025 compared to being overfunded by \$49.1 million at December 31, 2024. The improvement in the funded status was primarily due to actual return on assets exceeding the expected return on assets, partially offset by a decrease in discount rates. We contributed \$2.0 million and \$2.4 million to our pension plans in 2025 and 2024, respectively.

Our other postretirement benefit plans were underfunded, in aggregate by \$137.3 million and \$193.1 million at December 31, 2025 and 2024, respectively. The change in funded status was primarily due to actual return on assets exceeding the expected return on assets, partially offset by a decrease in discount rates. We contributed \$20.7 million and \$23.6 million to our other postretirement benefit plans in 2025 and 2024, respectively.

In 2025 and 2024, our Columbia Energy Group pension plan paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of \$6.5 million and \$7.2 million in 2025 and 2024, respectively. In 2025 and 2024, no remeasurement occurred related to lump sum payouts.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	5.28 %	5.58 %	5.45 %	5.66 %
Rate of Compensation Increases	4.00 %	4.00 %	N/A	N/A
Interest Crediting Rates	4.00 %	4.00 %	N/A	N/A
Health Care Trend Rates				
Trend for Next Year	N/A	N/A	9.52 %	9.77 %
Ultimate Trend	N/A	N/A	4.75 %	4.75 %
Year Ultimate Trend Reached	N/A	N/A	2034	2033

We expect to make contributions of approximately \$2.7 million to our pension plans and approximately \$18.3 million to our postretirement medical and life plans in 2026.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits
Year(s)		
2026	\$ 151.9	\$ 31.4
2027	130.3	31.3
2028	126.6	31.1
2029	119.4	31.0
2030	115.7	31.2
2031-2035	510.7	152.9

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2025, 2024 and 2023:

(in millions)	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	2025	2024	2023
Components of Net Periodic Benefit (Income) Cost⁽¹⁾						
Service cost	\$ 19.7	\$ 21.9	\$ 20.5	\$ 4.0	\$ 5.0	\$ 5.1
Interest cost	64.1	64.9	68.4	21.6	22.0	21.8
Expected return on assets	(92.4)	(95.3)	(94.5)	(16.8)	(16.1)	(15.1)
Amortization of prior service cost (credit)	0.1	0.1	0.1	(2.6)	(1.8)	(2.1)
Recognized actuarial loss	25.5	28.6	33.7	1.7	3.2	3.3
One-time charge	6.5	7.2	9.2	3.5	—	—
Total Net Periodic Benefits Cost	\$ 23.5	\$ 27.4	\$ 37.4	\$ 11.4	\$ 12.3	\$ 13.0

⁽¹⁾Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income. Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	2025	2024	2023
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	5.74 %	5.06 %	5.25 %	5.89 %	5.14 %	5.30 %
Discount rate - interest cost	5.28 %	4.88 %	5.06 %	5.35 %	4.89 %	5.07 %
Expected long-term rate of return on plan assets	7.30 %	7.02 %	7.00 %	7.09 %	7.06 %	6.96 %
Rate of compensation increases	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A
Interest crediting rates	4.00 %	4.00 %	4.00 %	N/A	N/A	N/A

We assumed a 7.30% and 7.09% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2025 pension benefits and other postretirement benefits costs. These rates were primarily based on asset mix and historical rates of return and were adjusted in 2025 due to changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

<i>(in millions)</i>	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service (credit) cost	\$ —	\$ —	\$ (30.3)	\$ —
Net actuarial (gain) loss	(5.6)	(13.1)	(13.7)	(26.4)
One time charge	(6.5)	(7.2)	(3.4)	—
Less: amortization of prior service cost	(0.1)	(0.1)	2.6	1.8
Less: amortization of net actuarial loss	(25.5)	(28.6)	(1.7)	(3.2)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	\$ (37.7)	\$ (49.0)	\$ (46.5)	\$ (27.8)
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	\$ (14.2)	\$ (21.6)	\$ (35.1)	\$ (15.5)

In August 2025, we communicated to plan participants of one of our OPEB plans the intention to move from a group self insured Medicare supplemental health plan to a Sponsored Health Reimbursement Account, with eligible retirees electing coverage through a Healthcare Exchange, effective on January 1, 2026. Given the intention of the plan and communication to participants, this was considered a plan amendment at the time of communication. This plan amendment triggered remeasurement of this plan, resulting in a decrease to the OPEB regulatory asset of \$5.7 million, a decrease to OPEB liability of \$23.3 million, and an increase to accumulated other comprehensive loss of \$17.6 million. Net periodic OPEB benefit cost for 2025 decreased by \$1.7 million as a result of the interim remeasurement. Additionally, this change resulted in the Net prior service (credit) cost of \$30.3 million in the table above.

In line with the remeasurement, key inputs, economic assumptions, and demographic assumptions changed to calculate the updated OPEB benefit obligation and the net periodic benefit cost at the interim remeasurement date for the plan that triggered settlement accounting. For remeasurement, we used a weighted-average discount rate of 5.53%, a weighted-average health care trend rate of 9.97% for next year and ultimate trend rate of 4.75% to be reached in 2034, and weighted-average expected return on assets of 6.88%.

17. Share-Based Compensation

Prior to May 19, 2020, we issued share-based compensation to employees and non-employee directors under the NiSource Inc. 2010 Omnibus Plan ("2010 Omnibus Plan"), which was most recently approved by stockholders at the Annual Meeting of Stockholders held on May 12, 2015. The 2010 Omnibus Plan provided for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and superseded the Director Stock Incentive Plan ("Director Plan") with respect to grants made after the effective date of the 2010 Omnibus Plan.

The stockholders approved and adopted the NiSource Inc. 2020 Omnibus Incentive Plan ("2020 Omnibus Plan") at the Annual Meeting of Stockholders held on May 19, 2020. The 2020 Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the 2010 Omnibus Plan with respect to grants made after the effective date of the 2020 Omnibus Plan.

The 2020 Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 10,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under the 2020 Omnibus Plan, the 2010 Omnibus Plan or any other equity plan under which awards were outstanding as of May 19, 2020. At December 31, 2025, there were 6,537,216 shares available for future awards under the 2020 Omnibus Plan.

We recognized stock-based employee compensation expense of \$40.9 million, \$32.1 million and \$23.9 million, during 2025, 2024 and 2023, respectively, as well as capitalized stock-based compensation cost of \$5.1 million, \$4.1 million, and zero during the same periods. We recognized related tax benefits of \$11.1 million, \$7.0 million and \$7.7 million, during 2025, 2024 and 2023, respectively. We recognized related excess tax benefits from the distribution of vested share-based employee compensation of \$5.1 million, \$2.0 million, and \$2.9 million in 2025, 2024 and 2023, respectively.

As of December 31, 2025, the total remaining unrecognized compensation cost related to non-vested awards amounted to \$59.2 million, which will be amortized over the weighted-average remaining requisite service period of 1.8 years.

Restricted Stock Units and Restricted Stock. We granted 550,614, 655,713, and 500,968 restricted stock units and shares of restricted stock to employees, subject to service conditions in 2025, 2024, and 2023, respectively. The total grant date fair value of the restricted stock units and shares of restricted stock during 2025, 2024, and 2023, respectively, was \$21.2 million, \$17.1 million, and \$13.7 million. The grant date fair value for the 2025, 2024 and 2023 awards is based on the average market price of our common stock at the date of each grant. The awards are expensed over the vesting period which is generally three years. As of December 31, 2025, 521,157, 508,444, and 316,439 non-vested restricted stock units and shares of restricted stock granted in 2025, 2024, and 2023, respectively, were outstanding. Our non-vested restricted stock units have a non-forfeitable right to dividend equivalents, with immaterial amounts paid in the periods ending December 31, 2025 and 2023. See Note 5, "Earnings Per Share," for further discussion.

In general, if an employee terminates employment before the service conditions lapse under the 2023, 2024 or 2025 awards due to (i) retirement or disability (as defined in the 2020 Omnibus Plan), or (ii) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the 2020 Omnibus Plan), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason, in general, will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee's date of termination.

A summary of our restricted stock unit award transactions for the year ended December 31, 2025 is as follows:

[Table of Contents](#)**NI SOURCE INC.****ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)****Notes to Consolidated Financial Statements**

<i>(shares)</i>	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit (\$)
Non-vested at December 31, 2024	1,328,120	26.49
Granted	550,614	38.59
Forfeited	(92,759)	29.98
Vested	(368,139)	26.57
Non-vested at December 31, 2025	1,417,836	31.19

Employee Performance Shares. We granted 643,683 performance shares subject to service, performance and/or market-based vesting conditions in 2025. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, achievement of relative total shareholder return, and other operational metrics, which make up 50%, 30%, and 20% of the issued awards respectively.

The non-GAAP financial measure is cumulative adjusted earnings per share, which we define as diluted earnings per share adjusted for certain items. Relative total shareholder return, a market-based vesting condition, which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price over the performance period, approximately) compared to the total shareholder return of a predetermined peer group of companies. A Monte Carlo analysis was used to value the portion of these awards dependent on the market-based vesting condition. The grant date fair value of the non-GAAP financial measure shares is based on the closing stock price of our common stock at the date of each grant, which will be expensed over the requisite service period of three years. The conditions for the remaining performance-based awards are based on operational goals of Annual Operational Index Scorecard (10%), Employee Engagement Index Score (5%), and Environmental Greenhouse Gas Reduction (5%).

In 2024, we granted 896,363 performance shares subject to service, performance and/or market-based vesting conditions. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, achievement of relative total shareholder return, and other operational metrics, which make up 55%, 25%, and 20% of the issued awards respectively. The conditions for the remaining performance-based awards are based on operational goals of Annual Operational Index Scorecard (10%), Employee Engagement Index Score (5%), and Environmental Greenhouse Gas Reduction (5%).

In 2023, we granted 649,088 performance shares subject to service, performance and/or market-based vesting conditions. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, achievement of relative total shareholder return, and other operational metrics, which make up 50%, 25%, and 25% of the issued awards respectively. The operational metrics consist of goals of economic inclusion (5%), OPEX ("Operating Expenses") Index (10%), Employee Engagement Index Score (5%), and Environmental GHG Reduction (5%). The OPEX Index is further defined by goals related to risk mitigation and modernization of our infrastructure.

The following table presents details of the performance awards described above.

Award Year	Service Conditions Lapse date	Performance Period	Award Conditions	Shares outstanding at 12/31/2025 (shares)	Grant Date Fair Value (in millions)
2025	2/29/2028	01/01/2025-12/31/2027	Non-GAAP Financial and Operational Measures	449,007	\$ 11.5
			Relative Total Shareholder Return	190,095	\$ 4.7
2024	2/26/2027	01/01/2024-12/31/2026	Non-GAAP Financial and Operational Measures	610,945	\$ 15.7
			Relative Total Shareholder Return	203,614	\$ 6.2
2023	2/28/2026	01/01/2023-12/31/2025	Non-GAAP Financial and Operational Measures	421,980	\$ 17.1
			Relative Total Shareholder Return	140,647	\$ 9.3

A summary of our performance award transactions for the year ended December 31, 2025 is as follows:

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit (\$)
Non-vested at December 31, 2024	1,719,223	24.96
Granted	643,683	41.26
Forfeited	(83,879)	31.36
Vested	(334,843)	32.91
Non-vested at December 31, 2025	1,944,184	18.93

Non-employee Director Awards. As of May 19, 2020, awards to non-employee directors may be made only under the 2020 Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's deferral election. Certain restricted stock units remain outstanding from the 2010 Omnibus Plan and the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2025, 292,441 restricted stock units are outstanding to non-employee directors under either the 2020 Omnibus Plan, the 2010 Omnibus Plan or the Director Plan. Of this amount, 50,612 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. Eligible salaried employees hired after January 1, 2010 and hourly and union employees hired after January 1, 2013 receive a non-elective company contribution of 4.5% of eligible pay payable in cash or shares of NiSource common stock. We also have a voluntary 401(k) savings plan covering eligible union and nonunion employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash or shares. Further, we have a retirement savings plan that provides for discretionary profit sharing contributions to eligible employees. For the years ended December 31, 2025, 2024 and 2023, we recognized 401(k) match, profit sharing and non-elective contribution expense of \$59.0 million, \$56.9 million and \$50.7 million, respectively.

18. Leases

Lease Descriptions. We are the lessee for substantially all of our leasing activity, which includes operating and finance leases for corporate and field offices, railcars, land, and fleet vehicles. Our corporate and field office leases and certain land leases have remaining terms between 1 and 38 years with options to renew the leases for up to 35 years. We lease railcars to transport coal to and from our electric generation facilities in Indiana. Our railcars are specifically identified in the lease agreements which have remaining lease terms between 1 and 3 years with options to renew for 1 year. Our fleet vehicles include trucks, trailers and equipment that have been customized specifically for use in the utility industry. We lease fleet vehicles for 1 year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. We elected the short-term lease practical expedient, allowing us to not recognize ROU assets or lease liabilities for all leases with a term of 12 months or less. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so.

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants. Lease contracts containing renewal and termination options are mostly exercisable at our sole discretion. Certain of our real estate and railcar leases include renewal periods in the measurement of the lease obligation if we have deemed the renewals reasonably certain to be exercised.

With respect to service contracts involving the use of assets, if we have the right to direct the use of the asset and obtain substantially all economic benefits from the use of an asset, we account for the service contract as a lease. Unless specifically provided to us by the lessor, we utilize NiSource's collateralized incremental borrowing rate commensurate to the lease term as the discount rate for all of our leases. ASC 842 permits a lessee, by class of underlying asset, not to separate nonlease components from lease components. Our policy is to apply this expedient for our leases of fleet vehicles, IT assets and railcars when calculating their respective lease liabilities.

Lease costs for the years ended December 31, 2025 and December 31, 2024 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized as part of the cost of another asset. Income statement presentation for these costs (when ultimately recognized on the income statement) is also included:

Year Ended December 31, (in millions)	Income Statement Classification	2025	2024
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	\$ 20.5	\$ 27.1
Interest on lease liabilities	Interest expense, net	12.9	13.5
Total finance lease cost		33.4	40.6
Operating lease cost	Operation and maintenance	14.3	14.7
Total lease cost		\$ 47.7	\$ 55.3

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

At December 31, (in millions)	Balance Sheet Classification	2025	2024
Assets			
Finance leases	Net Property, Plant and Equipment	\$ 249.8	\$ 222.9
Operating leases	Deferred charges and other	25.8	26.4
Total leased assets		\$ 275.6	\$ 249.3
Liabilities			
Current			
Finance leases	Current portion of long-term debt	\$ 19.7	\$ 22.9
Operating leases	Other accruals	9.7	9.1
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year	254.3	223.3
Operating leases	Other noncurrent liabilities and deferred credits	17.2	18.2
Total lease liabilities		\$ 300.9	\$ 273.5

Other pertinent information related to leases was as follows:

Year Ended December 31, <i>(in millions)</i>	2025		2024	
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows used for finance leases	\$	14.5	\$	11.2
Operating cash flows used for operating leases		15.7		14.5
Financing cash flows used for finance leases		22.0		26.9
Right-of-use assets obtained in exchange for lease obligations				
Finance leases		50.2		65.9
Operating leases	\$	13.9	\$	12.2

	December 31, 2025		December 31, 2024	
Weighted-average remaining lease term (years)				
Finance leases		21.8		20.5
Operating leases		5.3		5.6
Weighted-average discount rate				
Finance leases		5.7 %		5.6 %
Operating leases		4.5 %		4.5 %

Maturities of our lease liabilities as of December 31, 2025 were as follows:

As of December 31, 2025, <i>(in millions)</i>	Total	Finance Leases	Operating Leases
2026	\$ 43.3	\$ 32.6	\$ 10.7
2027	32.5	27.4	5.1
2028	30.0	26.2	3.8
2029	24.5	21.3	3.2
2030	24.4	22.3	2.1
Thereafter	373.7	368.1	5.6
Total lease payments	528.4	497.9	30.5
Less: Imputed interest	(227.5)	(223.9)	(3.6)
Total	\$ 300.9	\$ 274.0	\$ 26.9
Reported as of December 31, 2025			
Short-term lease liabilities	29.4	19.7	9.7
Long-term lease liabilities	271.5	254.3	17.2
Total lease liabilities	\$ 300.9	\$ 274.0	\$ 26.9

19. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2025 and their maturities were:

<i>(in millions)</i>	Total	2026	2027	2028	2029	2030	After
Long-term debt ⁽¹⁾	\$ 15,345.0	\$ —	\$ 1,090.0	\$ 1,055.0	\$ 1,350.0	\$ 1,000.0	\$ 10,850.0
Interest payments on long-term debt	12,361.2	729.1	725.1	675.0	647.3	575.9	9,008.8
Finance leases ⁽²⁾	497.9	32.6	27.4	26.2	21.3	22.3	368.1
Operating leases ⁽³⁾	30.5	10.7	5.1	3.8	3.2	2.1	5.6
Energy commodity and capacity contracts	476.9	315.9	116.7	9.3	7.6	4.6	22.8
Service obligations:							
Pipeline service obligations	2,829.1	809.5	879.3	482.3	326.5	156.6	174.9
IT service obligations	322.1	98.3	81.8	61.7	43.0	37.3	—
Plant equipment purchase obligations	103.3	87.6	10.4	5.3	—	—	—
Other liabilities ⁽⁴⁾	120.3	74.0	10.1	9.5	8.4	8.0	10.3
Total contractual obligations	\$ 32,086.3	\$ 2,157.7	\$ 2,945.9	\$ 2,328.1	\$ 2,407.3	\$ 1,806.8	\$ 20,440.5

⁽¹⁾ Long-term debt balance excludes unamortized issuance costs and discounts of \$141.5 million and finance leases of \$274.0 million.

⁽²⁾ Finance lease payments shown above are inclusive of interest totaling \$223.9 million.

⁽³⁾ Operating lease payments shown above are inclusive of interest totaling \$3.6 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so as they are renewed month-to-month after the first year.

⁽⁴⁾ Other liabilities shown above are primarily related to the current EPC contract and ongoing maintenance service agreements for our renewable joint ventures.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our energy commodity contracts are for the purchase of physical quantities of natural gas, electricity, coal and purchases of electric capacity. Our service obligations, consisting of pipeline service obligations and IT service obligations, encompass a broad range of business support and maintenance functions which are generally described below. Our plant equipment purchase obligations are for plant equipment, typically for generation assets, with long lead times that require payments made over time.

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity, coal and purchases of electric capacity. These amounts represent the minimum quantity of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2025.

NIPSCO has PPAs representing approximately 1,200 MW of capacity, with contracts expiring between 2038 and 2045. No minimum quantities are specified within these agreements due to the variability of electricity generation, so no amounts related to these contracts are included in the table above. Upon early termination of one of these agreements by NIPSCO for any reason (other than material breach by the counterparties), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2030 to 2044, require us to pay fixed monthly charges.

NIPSCO has contracts with three rail operators providing coal transportation services for which there are certain minimum payments. These service contracts extend for various periods from 2026 through 2028.

We have executed agreements with multiple IT service providers. The agreements extend for various periods through 2030.

B. Guarantees and Indemnities. We and certain of our subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish

the subsidiaries' intended commercial purposes. At December 31, 2025 and 2024, we issued letters of credit of \$119.0 million and \$9.4 million, respectively, for the benefit of third parties.

We provide guarantees related to our future performance under BTAs for our renewable generation projects. At December 31, 2025 and 2024, our guarantees for multiple BTAs totaled \$27.2 million and \$1,127.5 million, respectively. The amount of each guaranty will decrease upon the substantial completion of the construction of the facilities. See “- E. Other Matters - Generation Transition,” below for more information.

We provide guarantees related to some of our rail and pipeline service agreements. If we do not meet our contractual obligations under the terms of these agreements we would be required to pay up to a maximum of \$52.0 million.

C. Legal Proceedings. From time to time, various legal and regulatory claims and proceedings are pending or threatened against the Company and its subsidiaries. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company establishes reserves whenever it believes it to be appropriate for pending litigation matters. However, the actual results of resolving the pending litigation matters may be substantially higher than the amounts reserved. If one or more other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim, proceeding or investigation would not have a material adverse effect on our results of operations, financial position or liquidity.

Other Claims and Proceedings. We are also party to certain other claims, regulatory and legal proceedings arising in the ordinary course of business in each state in which we have operations, and based upon an investigation of these matters and discussion with legal counsel, we believe the ultimate outcome of such other legal proceedings to be individually, or in aggregate, not material at this time.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects the majority of environmental assessment and remediation costs and asset retirement costs, further described below, to be recoverable through rates. See Note 11, "Asset Retirement Obligations" and Note 12, "Regulatory Matters," for additional detail.

As of December 31, 2025 and 2024, we had recorded a liability of \$82.6 million and \$91.8 million, respectively, to cover environmental remediation at various sites. This liability is included in "Other accruals" and "Other noncurrent liabilities and deferred credits" in the Consolidated Balance Sheets. We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. At this time, we cannot estimate the full cost of remediating properties that have not yet been investigated, but it is possible that the future costs could be material to the Consolidated Financial Statements.

MGP. We maintain a program to identify and investigate former MGP sites where gas distribution subsidiaries or predecessors may have liability. The program has identified 41 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were identified during the update completed as of June 30, 2025. Our total estimated liability related to the facilities subject to remediation was \$75.5 million and \$86.4 million at December 31, 2025 and 2024, respectively. The liability represents our best estimate of the probable cost to remediate the MGP sites. Our model indicates that it is reasonably possible that remediation costs could vary by as much as \$16.5 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. NIPSCO continues to meet the compliance requirements established by the EPA for the regulation of CCRs. The CCR rule requirements currently in effect required revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the requirements that will be established by environmental authorities, compliance strategies that will be used and the preliminary nature of available data used to estimate costs. As allowed by the rule, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

On May 8, 2024, the EPA finalized changes to the current CCR regulations ("Legacy CCR Rule") which address inactive surface impoundments at inactive facilities, referred to as legacy impoundments, and CCR management units ("CCRMUs") at inactive and active facilities. The rule largely requires these newly regulated units to conform to existing requirements, such as groundwater monitoring, closure requirements, and post-closure care. During 2025, we accrued an additional \$48.9 million to cover probable and estimable compliance activities associated with the Legacy CCR Rule. NIPSCO continues to assess whether existing legal obligations associated with the retirement of certain facilities must be revised and to estimate probable additional required asset retirement costs. NIPSCO expects to receive recovery of any such costs through existing and future depreciation rates.

E. Other Matters

Generation Transition. In October 2024, NIPSCO contracted with a developer to convert the previously approved Templeton PPA to a BTA and in February 2025 filed a CPCN with the IURC seeking approval of the full ownership BTA structure. In September 2025, the IURC granted NIPSCO a CPCN to acquire Templeton through the full ownership BTA structure. NIPSCO's purchase obligation under Templeton is dependent on timely completion of construction. Certain agreements require NIPSCO to make partial payments upon the developer's completion of significant construction milestones.

In January 2025, the Fairbanks project achieved mechanical completion, resulting in NIPSCO making a \$336.6 million payment to the developer. In May 2025, the Fairbanks project achieved substantial completion, resulting in NIPSCO making a \$141.4 million payment to the developer in June 2025. In December 2025, the Fairbanks project achieved final completion, resulting in NIPSCO making a \$3.6 million payment to the developer.

In January 2025, the Dunns Bridge II project achieved substantial completion, resulting in NIPSCO making a \$217.6 million payment to the developer in February 2025. In October 2025, the Dunns Bridge II project achieved final completion resulting in a NIPSCO making a \$4.2 million payment to the developer.

In June 2025, the Gibson project achieved mechanical completion, resulting in NIPSCO making a \$262.4 million payment to the developer. In August 2025, the Gibson project achieved substantial completion, resulting in NIPSCO making a \$133.7 million payment to the developer in September 2025.

NIPSCO Minority Interest Transaction. In December 2023, pursuant to the terms of the BIP Purchase Agreement and simultaneously with the closing of the NIPSCO Minority Interest Transaction, Blackstone, NIPSCO Holdings I, NIPSCO Holdings II and NiSource entered into an Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II. In January 2024, BIP transferred a 4.5% portion of its equity interest to one of its affiliates and the members of NIPSCO Holdings II entered into a Second Amended and Restated Limited Liability Company Operating Agreement of NIPSCO Holdings II. In October 2025, the members of NIPSCO Holdings II entered into a Third Amended and Restated LLC Agreement of NIPSCO Holdings II (the "Amended LLC Agreement"), which, among other changes, increased the amount and time period for additional mandatory capital contributions required to be contributed by the members affiliated with Blackstone by \$175 million and seven years, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof, and amended certain provisions to facilitate NIPSCO Holdings II and its subsidiaries' provision of electric service to

data center customers (and related activities) and their related contracts and arrangements with Generation Holdings II and its subsidiaries. The members of NIPSCO Holdings II that are affiliates of Blackstone must vote their equity holdings under the Amended LLC Agreement as one investor. Refer to Note 4, "Noncontrolling Interests," in the Notes to the Consolidated Financial Statements for more information on this transition.

GenCo Minority Interest Transaction. In October 2025, NiSource issued a 19.9% indirect equity interest in NiSource's wholly-owned subsidiary GenCo to BIP Orion Holdco L.P. and BIP Orion Holdco II L.P., affiliates of Blackstone (collectively, "Blackstone Investor"), in exchange for \$35.2 million in cash contributions to Generation Holdings II through the Generation Holdings II LLC Agreement. We analyzed the Generation Holdings II LLC Agreement and determined that we maintain the decision-making activities over Generation Holdings II and its wholly owned subsidiary GenCo, making Generation Holdings II a consolidated VIE. Generation Holding II is considered a VIE as it passes the variability of its operating results through to its shareholders (Generation Holdings I and Blackstone Investor) and has insufficient equity to finance its activities without additional subordinated financial support.

Refer to Note 4, "Noncontrolling Interest," for detailed discussion of accounting for the GenCo Minority Interest Transaction.

The foregoing descriptions of the Generation Holdings II LLC Agreement and the Amended LLC Agreement do not purport to be complete and are qualified in their entirety by reference to the terms and conditions of the Generation Holdings II LLC Agreement and Amended LLC Agreement, which are filed as Exhibits 10.17 and 10.16, respectively, and are incorporated by reference herein.

EPC Agreements. GenCo has entered into certain EPC contracts to construct generation capacity assets to support the ADS Contract, requiring payments at specified periods. The assets contemplated by these contracts are subject to IURC approval. We may terminate for convenience the EPC Contracts and pay certain incurred project costs and termination fees if the ADS Contract is terminated or IURC approval of the underlying assets is not obtained. Amounts that will be owed in the event of termination are included in the table above.

20. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

<i>(in millions)</i>	Gains and Losses on Securities ⁽¹⁾	Gains and Losses on Cash Flow Hedges ⁽¹⁾	Pension and OPEB Items ⁽¹⁾	Accumulated Other Comprehensive Loss ⁽¹⁾
Balance as of December 31, 2022	\$ (11.2)	\$ (12.6)	\$ (13.3)	\$ (37.1)
Other comprehensive (loss) income before reclassifications	3.1	(0.5)	(1.4)	1.2
Amounts reclassified from accumulated other comprehensive loss	0.8	0.3	1.2	2.3
Net current-period other comprehensive (loss) income	3.9	(0.2)	(0.2)	3.5
Balance as of December 31, 2023	\$ (7.3)	\$ (12.8)	\$ (13.5)	\$ (33.6)
Other comprehensive (loss) income before reclassifications	1.5	—	(1.2)	0.3
Amounts reclassified from accumulated other comprehensive loss	1.8	(0.4)	1.5	2.9
Net current-period other comprehensive (loss) income	3.3	(0.4)	0.3	3.2
Balance as of December 31, 2024	\$ (4.0)	\$ (13.2)	\$ (13.2)	\$ (30.4)
Other comprehensive income before reclassifications	5.0	—	19.5	24.5
Amounts reclassified from accumulated other comprehensive loss	(0.9)	(0.4)	1.0	(0.3)
Net current-period other comprehensive income (loss)	4.1	(0.4)	20.5	24.2
Balance as of December 31, 2025	\$ 0.1	\$ (13.6)	\$ 7.3	\$ (6.2)

⁽¹⁾All amounts are net of tax. Amounts in parentheses indicate debits.

21. Business Segment Information

Our reportable segments reflect the manner in which our business is managed and our resources are allocated. Following the consummation of the NIPSCO Minority Interest Transaction, we revised how we evaluate results and allocate resources across our business with an increased focus on operating performance at the state level. Refer to Note 4, "Noncontrolling Interests," for additional information on the NIPSCO Minority Interest Transaction. At December 31, 2025, our operations are divided into two primary reportable segments, the Columbia Operations and the NIPSCO Operations segments. Columbia Operations aggregates the results of the fully regulated and wholly owned subsidiaries of NiSource Gas Distribution Group, Inc. (a holding company that owns Columbia of Kentucky, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, and Columbia of Virginia). Each Columbia distribution company is an operating segment which we aggregate to form the Columbia Operations reportable segment. NIPSCO Operations includes the results of NIPSCO Holdings I and its majority-owned subsidiaries, including NIPSCO, which has fully regulated gas and electric operations in northern Indiana. Our historical segment disclosures have been recast to be consistent with the current presentation.

The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" in the subsequent reconciliation table and primarily are comprised of interest expense on holding company debt and unallocated corporate costs and activities, as well as new business development costs associated with GenCo. Refer to Note 3, "Revenue Recognition," for additional information on our segments and their sources of revenues. The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on financing, dividends and taxes at the corporate level on a consolidated basis. We provide this measure to our Chief Operating Decision Maker, the CEO, who utilizes this measure to make operating segment level strategy decisions based on budget-to-actual variances and against prior periods to allocate resources accordingly. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, 2025 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External revenue	\$ 3,330.0	\$ 3,307.4	\$ 6,637.4
Intersegment revenue	13.3	1.1	14.4
Total Operating Revenue	\$ 3,343.3	\$ 3,308.5	\$ 6,651.8
Cost of energy	819.8	764.7	1,584.5
O&M	923.7	848.9	1,772.6
Depreciation	451.2	680.6	1,131.8
Total other taxes	253.2	75.5	328.7
Other segment items ⁽¹⁾	0.3	0.7	1.0
Operating Income	\$ 895.1	\$ 938.1	\$ 1,833.2
Capital Expenditures⁽²⁾	\$ 1,213.0	\$ 2,508.9	\$ 3,721.9
Assets	\$ 15,903.7	\$ 18,126.7	\$ 34,030.4

⁽¹⁾Other segment items consists of Loss (gain) on Sale or Impairment of Assets and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.

⁽²⁾Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

Year Ended December 31, 2024 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External revenue	\$ 2,703.2	\$ 2,751.0	\$ 5,454.2
Intersegment revenue	12.8	1.0	13.8
Total Operating Revenue	\$ 2,716.0	\$ 2,752.0	\$ 5,468.0
Operating Expenses			
Cost of energy	514.7	617.5	1,132.2
O&M	837.5	761.4	1,598.9
Depreciation	409.1	590.3	999.4
Total other taxes	218.6	64.3	282.9
Other segment items ⁽¹⁾	7.4	(1.3)	6.1
Operating Income	\$ 728.7	\$ 719.8	\$ 1,448.5
Capital Expenditures⁽²⁾	\$ 1,209.0	\$ 2,252.4	\$ 3,461.4
Assets	\$ 14,769.5	\$ 15,823.5	\$ 30,593.0

⁽¹⁾Other segment items consists of Loss(gain) on Sale or Impairment of Assets and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.

⁽²⁾Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

Year Ended December 31, 2023 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External revenue	\$ 2,733.9	\$ 2,770.7	\$ 5,504.6
Intersegment revenue	12.2	0.9	13.1
Total Operating Revenue	\$ 2,746.1	\$ 2,771.6	\$ 5,517.7
Operating Expenses			
Cost of energy	645.0	888.3	1,533.3
O&M	792.3	787.7	1,580.0
Depreciation	371.7	493.8	865.5
Total other taxes	198.8	57.9	256.7
Other segment items ⁽¹⁾	—	2.2	2.2
Operating Income	\$ 738.3	\$ 541.7	\$ 1,280.0
Capital Expenditures⁽²⁾	\$ 1,159.6	\$ 1,294.8	\$ 2,454.4
Assets	\$ 13,664.5	\$ 13,962.6	\$ 27,627.1

⁽¹⁾Other segment items consists of proceeds from a property insurance settlement related to the Greater Lawrence Incident and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.

⁽²⁾Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

To reconcile the segment tables above to consolidated NiSource:

Year Ended December 31, 2025 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	\$ 6,651.8	\$ 600.1	\$ (609.7)	\$ 6,642.2
Operating Income	1,833.2	2.1	—	1,835.3
Capital Expenditures	3,721.9	329.7	—	4,051.6
Assets	34,030.4	1,828.3	—	35,858.7

Year Ended December 31, 2024 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	\$ 5,468.0	\$ 581.9	\$ (594.8)	\$ 5,455.1
Operating Income	1,448.5	7.0	—	1,455.5
Capital Expenditures	3,461.4	231.1	—	3,692.5
Assets	30,593.0	1,195.1	—	31,788.1

Year Ended December 31, 2023 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	\$ 5,517.7	\$ 504.6	\$ (516.9)	\$ 5,505.4
Operating Income	1,280.0	15.5	—	1,295.5
Capital Expenditures	2,454.4	236.3	—	2,690.7
Assets	27,627.1	3,450.1	—	31,077.2

22. Other, Net

The following table displays the components of Other, Net included on the Statements of Consolidated Income:

Year Ended December 31, (in millions)	2025	2024	2023
Interest income	\$ 10.2	\$ 10.4	\$ 9.0
AFUDC equity	32.7	75.1	25.2
Charitable contributions	(4.8)	(5.4)	(1.8)
Pension and other postretirement non-service cost ⁽¹⁾	(13.0)	(13.5)	(24.0)
Tax penalty	(4.0)	(0.7)	—
Heating assistance	(2.1)	(0.5)	(0.8)
Miscellaneous	1.1	(0.9)	0.4
Total Other, net	\$ 20.1	\$ 64.5	\$ 8.0

⁽¹⁾ See Note 16, "Pension and Other Postemployment Benefits," for additional information.

23. Interest Expense, Net

The following table displays the components of Interest Expense, Net included on the Statements of Consolidated Income:

Year Ended December 31, (in millions)	2025	2024	2023
Interest on long-term debt	\$ 647.8	\$ 506.2	\$ 404.1
Interest on short-term borrowings	36.7	43.2	108.9
Debt discount/cost amortization	15.2	13.8	13.5
Accounts receivable securitization fees	1.4	1.5	2.7
Allowance for borrowed funds used and interest capitalized during construction	(37.8)	(40.1)	(25.3)
Debt-based post-in-service carrying charges	(47.4)	(26.4)	(30.7)
Other	23.1	19.0	16.4
Total Interest Expense, net	\$ 639.0	\$ 517.2	\$ 489.6

24. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023:

Year Ended December 31, (in millions)	2025	2024	2023
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	\$ 479.9	\$ 367.0	\$ 315.0
Assets acquired under a finance lease	50.2	65.9	64.5
Assets acquired under an operating lease	13.9	12.2	5.6
Assets recorded for asset retirement obligations ⁽¹⁾	88.7	277.4	61.1
Schedule of interest and income taxes paid:			
Cash paid for interest on debt, net of interest capitalized amounts	\$ 557.1	\$ 468.2	\$ 433.9
Cash paid for interest on finance leases	14.5	11.2	8.6
Cash paid for income taxes, net of refunds	3.3	4.3	9.4

⁽¹⁾See Note 11, "Asset Retirement Obligations," for additional information.

**NISOURCE INC.
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS**

Twelve months ended December 31, 2025

<i>(\$ in millions)</i>	Balance Jan. 1, 2025	Additions		Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2025
		Charged to Costs and Expenses	Charged to Other Account ⁽¹⁾		
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	\$ 23.7	\$ 40.8	\$ 40.9	\$ 64.8	\$ 40.6
Reserve for deferred charges and other	1.1	—	0.2	—	1.3

Twelve months ended December 31, 2024

<i>(\$ in millions)</i>	Balance Jan. 1, 2024	Additions		Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2024
		Charged to Costs and Expenses	Charged to Other Account ⁽¹⁾		
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	\$ 22.9	\$ 23.2	\$ 32.3	\$ 54.7	\$ 23.7
Reserve for deferred charges and other	1.3	—	(0.2)	—	1.1

Twelve months ended December 31, 2023

<i>(\$ in millions)</i>	Balance Jan. 1, 2023	Additions		Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2023
		Charged to Costs and Expenses	Charged to Other Account ⁽¹⁾		
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	\$ 23.9	\$ 23.4	\$ 36.6	\$ 61.0	\$ 22.9
Reserve for deferred charges and other	1.0	—	0.3	—	1.3

⁽¹⁾ Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset or the movement of the reserve between short term and long term.

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our CEO and CFO are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our CEO and CFO concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our CEO and CFO, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. We conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this Annual Report on Form 10-K.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is included herein.

Changes in Internal Controls

There have been no changes during the last fiscal quarter in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the “Company”) as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Company and our report dated February 11, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 11, 2026

NiSOURCE INC.

ITEM 9B. OTHER INFORMATION

Director and Officer Trading Arrangements

The following table describes any contracts, instructions or written plans for the sale or purchase of NiSource securities and intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Exchange Act that were adopted by our directors and executive officers during the quarter ended December 31, 2025:

Name and Title	Date of Adoption of Rule 10b5-1 Trading Plan	Scheduled Expiration Date of Rule 10b5-1 Trading Plan⁽¹⁾	Aggregate Number of Securities to Be Purchased or Sold
Shawn Anderson Executive Vice President, Chief Financial Officer	11/10/2025	5/29/2026	Sale of up to 12,500 shares of common stock

⁽¹⁾A trading plan may also expire on such earlier date that all transactions under the trading plan are completed.

During the quarter ended December 31, 2025, none of our directors or executive officers terminated a Rule 10b5-1 trading plan or adopted or terminated a non-Rule 10b5-1 trading arrangement (as defined in Item 408(c) of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K and the information with respect to our insider trading policy set forth below, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," "Corporate Governance - Board Committee Composition," "Corporate Governance - Code of Business Conduct," and "Delinquent Section 16(a) Reports" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2026.

Insider Trading Policy

The Company has adopted an Insider Trading Policy, our "Securities Transaction Compliance Policy", governing the purchase, sale, and/or other dispositions of the Company's securities by our directors and all employees, including officers as defined under Rule 16a-1(f) of the Securities Exchange Act of 1934 and certain designated employees as well as their immediate family and members of their households, that we believe is reasonably designed to promote compliance with insider trading laws, rules and regulations and the exchange listing standards applicable to us. A copy of our policy is filed as Exhibit 19.1 to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Compensation and Human Capital Committee Interlocks and Insider Participation," "2025 Director Compensation," "2025 Executive Compensation," "Compensation Discussion and Analysis (CD&A)," "Assessment of Risk," "2025 Pay Versus Performance," and "Compensation and Human Capital Committee Report" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2026.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management," and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2026.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2026.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Registered Public Accounting Firm Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2026.

PART IVITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULESFinancial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

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Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 of the NiSource Inc. Form 8-K filed on October 31, 2025).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of the NiSource Inc. Form 8-K filed on October 31, 2025).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(3.1)	Articles of Incorporation of NiSource Inc., as amended and restated through October 21, 2024 (incorporated by reference to Exhibit 3.3 to the NiSource Inc. Form 8-K filed on October 22, 2024).
(3.2)	Bylaws of NiSource Inc., as amended and restated through October 21, 2024 (incorporated by reference to Exhibit 3.4 to the NiSource Inc. Form 8-K filed on October 22, 2024).
(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).
(4.2)	First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).
(4.3)	Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).
(4.4)	Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).
(4.5)	Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).
(4.6)	Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).

NiSOURCE INC.

- (4.7) Form of 4.375% Notes due 2047 (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on May 17, 2017).
- (4.8) Form of 3.950% Notes due 2048 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on September 8, 2017).
- (4.9) Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3](#) filed November 30, 2017 (Registration No. 333-214360)).
- (4.10) Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on December 1, 2017).
- (4.11) Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 10-Q](#) filed on May 2, 2018).
- (4.12) Fourth Supplemental Indenture, dated as of December 18, 2023, between NiSource, Inc. and The Bank of New York Mellon, as trustee, relating to the 7.99% Medium-Term Notes due 2027 and the 6.78% Senior Notes due 2027 (incorporated by reference to [Exhibit 10.1 to the NiSource Inc. Form 8-K](#) filed on December 18, 2023).
- (4.13) Subordinated Indenture, dated as of May 16, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.2 to the NiSource Form 8-K](#) filed on May 16, 2024).
- (4.14) First Supplemental Indenture, dated as of May 16, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.3 to the NiSource Form 8-K](#) filed on May 16, 2024).
- (4.15) Second Supplemental Indenture, dated as of September 09, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.2 to the NiSource Form 8-K](#) filed on September 09, 2024).
- (4.16) Form of 2.950% Notes due 2029 (incorporated by reference to [Exhibit 4.1 to NiSource Inc. Form 8-K](#) filed on August 12, 2019).
- (4.17) Form of 3.600% Notes due 2030 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on April 8, 2020).
- (4.18) Form of 0.950% Notes due 2025 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on August 18, 2020).
- (4.19) Form of 1.700% Notes due 2031 (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on August 18, 2020).
- (4.20) Form of 5.000% Notes due 2052 (incorporated by reference to [Exhibit 4.1 of the NiSource Inc. Form 8-K](#) filed on June 10, 2022).
- (4.21) Form of 5.250% Notes due 2028 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on March 24, 2023).
- (4.22) Form of 5.400% Notes due 2033 (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on June 9, 2023).
- (4.23) Form of 5.350% Notes due 2034 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on March 14, 2024).
- (4.24) Form of 6.950% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2054 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on May 16, 2024).
- (4.25) Form of 5.200% Notes due 2029 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on June 24, 2024).
- (4.26) Form of 6.375% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on September 09, 2024).
- (4.27) Form of 6.25% Notes due 2040 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on December 6, 2010).

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- (4.28) Form of 5.95% Notes due 2041 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on June 10, 2011).
- (4.29) Form of 5.80% Notes due 2042 (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on November 17, 2011).
- (4.30) Form of 5.25% Notes due 2043 (incorporated by reference to [Exhibit 4.2 to the NiSource Inc. Form 8-K](#) filed on June 14, 2012).
- (4.31) Form of 4.80% Notes due 2044 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on April 12, 2013).
- (4.32) Form of 5.65% Notes due 2045 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on October 7, 2013).
- (4.33) Form of 5.850% Notes due 2055 (incorporated by reference to [Exhibit 4.1 to the NiSource. Form 8-K](#) filed on March 27, 2025).
- (4.34) Form 5.350% Notes due 2035 (incorporated by reference to [Exhibit 4.1 to the NiSource. Form 8-K](#) filed on June 27, 2025).
- (4.35) Third Supplemental Indenture, dated as of November 7, 2025 between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on November 7, 2025).
- (4.36) Form of 5.750% Fixed-to-Fixed Reset Rate Junior Subordinated Note due 2056 (incorporated by reference to [Exhibit 4.1 to the NiSource Inc. Form 8-K](#) filed on November 7, 2025).
- (4.37) Description of NiSource Inc.'s Securities Registered Under Section 12 of the Exchange Act (incorporated by reference to [Exhibit 4.32 to the NiSource Inc. Form 10-K](#) filed on February 12, 2025).
- (10.1) Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*
- (10.2) Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to [Exhibit 10.21 to the NiSource Inc. Form 10-K](#) filed on February 19, 2013).*
- (10.3) Amended and Restated Executive Deferred Compensation Plan, dated August 12, 2024 (incorporated by reference to [Exhibit 10.1 of the NiSource Inc. Form 10-Q](#) filed on October 30, 2024).*
- (10.4) Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to [Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K](#) filed on August 26, 2005).
- (10.5) Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to [Exhibit 10.30 to the NiSource Inc. Form 10-K](#) filed on February 27, 2009).
- (10.6) Form of Change in Control and Termination Agreement (incorporated by reference to [Exhibit 10.1 to the NiSource Inc. Form 10-Q](#) filed on August 2, 2017).*
- (10.7) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of February 1, 2019 (incorporated by reference to [Exhibit C to the NiSource Inc. Definitive Proxy Statement](#) to Stockholders for the Annual Meeting to be held on May 7, 2019, filed on April 1, 2019).
- (10.8) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of January 25, 2024 (incorporated by reference to [Appendix B to the NiSource Inc. Definitive Proxy Statement](#) to Stockholders for the Annual Meeting to be held on May 13, 2024, filed on April 1, 2024).
- (10.9) NiSource Inc. Supplemental Executive Retirement Plan, as amended and restated effective November 1, 2020 (incorporated by reference to [Exhibit 10.4 to the NiSource Inc. Form 10-Q](#) filed on November 2, 2020).*
- (10.10) Pension Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to [Exhibit 10.5 to the NiSource Inc. Form 10-Q](#) filed on November 2, 2020).
- (10.11) Savings Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to [Exhibit 10.6 to the NiSource Inc. Form 10-Q](#) filed on November 2, 2020).*

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- (10.12) First Amendment to the Savings Restoration Plan for NiSource Inc. and Affiliates dated October 12, 2023 and effective November 1, 2020 (incorporated by reference to [Exhibit 10.24 to the NiSource Inc. Form 10-K](#) filed on February 21, 2024).*
- (10.13) [NiSource Inc. Executive Severance Policy, as amended and restated effective January 1, 2026](#).* **
- (10.14) NiSource Next Voluntary Separation Program, effective as of August 5, 2020 (incorporated by reference to [Exhibit 10.8 to the NiSource Inc. Form 10-Q](#) filed on November 2, 2020).*
- (10.15) Seventh Amended and Restated Revolving Credit Agreement, dated as of December 11, 2025, among NiSource Inc., as Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, JPMorgan Chase Bank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Co-Syndication Agents, Credit Suisse AG, New York Branch, Wells Fargo Bank, National Association, and Bank of America, National Association, as Co-Documentation Agents, Barclays Bank PLC and MUFG Bank, Ltd., as Co-Sustainability Structuring Agents, and Barclays Bank PLC, JPMorgan Chase Bank, N.A. MUFG Bank, Ltd., Credit Suisse Loan Funding LLC, Wells Fargo Securities, LLC, BofA Securities, Inc., BMO Capital Markets Corp. and Mizuho Bank Ltd., as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to [Exhibit 10.1 of the NiSource Inc. Form 8-K](#) filed on December 11, 2025).
- (10.16) Third Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II LLC, dated October 28, 2025 (incorporated by reference to [Exhibit 10.2 to the NiSource Inc. Form 10-Q](#) filed on October 29, 2025).***
- (10.17) [Amended and Restated Limited Liability Company Agreement of Generation Holdings II LLC, dated October 28, 2025](#).** ***
- (10.18) 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders](#) for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*
- (10.19) First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.2 to the NiSource Inc. Form 10-K](#) filed on February 18, 2014).*
- (10.20) 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders](#) for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*
- (10.21) Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.1 to the NiSource Inc. Form 8-K](#) filed October 23, 2015).*
- (10.22) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.1 to NiSource Inc. Form 10-Q](#) filed on August 2, 2011).*
- (10.23) Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to [Exhibit 10.3 to the NiSource Inc. Form 10-Q](#) filed on November 3, 2015).*
- (10.24) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.18 to the NiSource Inc. Form 10-K](#) filed on February 22, 2017).*
- (10.25) Form of Cash-Based Award Agreement (incorporated by reference to [Exhibit 10.41 of the NiSource Form 10-K](#) filed on February 28, 2020).*
- (10.26) 2020 Omnibus Incentive Plan (incorporated by reference to [Exhibit A to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 19, 2020](#), filed on April 13, 2020).*
- (10.27) First Amendment to the NiSource Inc. 2020 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.1 of the NiSource Inc. Form 10-Q](#) filed on May 4, 2022).*
- (10.28) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2020 Omnibus Incentive Plan (incorporated by reference to [Exhibit 10.2 of the NiSource Inc. Form 10-Q](#) filed on August 5, 2020).*
- (10.29) Form of Restricted Stock Unit Award Agreement. (incorporated by reference to [Exhibit 10.53 to the NiSource Inc. Form 10-K](#) filed on February 17, 2021).*
- (10.30) Form of Performance Share Unit Award Agreement. (incorporated by reference to [Exhibit 10.54 to the NiSource Inc. Form 10-K](#) filed on February 17, 2021).*
- (10.31) Form of Special Performance Share Unit Award Agreement. (incorporated by reference to [Exhibit 10.55 to the NiSource Inc. Form 10-K](#) filed on February 17, 2021).*

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- (10.32) Form of Restricted Stock Unit Award Agreement.(incorporated by reference to [Exhibit 10.57 to the NiSource Inc. Form 10-K](#) filed on February 22, 2023).*
- (10.33) Form of Performance Share Unit Award Agreement (incorporated by reference to [Exhibit 10.58 to the NiSource Inc. Form 10-K](#) filed on February 22, 2023).*
- (10.34) Form of Restricted Stock Unit Award Agreement. (incorporated by reference to [Exhibit 10.59 to the NiSource Inc. Form 10-K](#) filed on February 22, 2023).*
- (10.35) Form of Performance Share Unit Award Agreement. (incorporated by reference to [Exhibit 10.60 to the NiSource Inc. Form 10-K](#) filed on February 22, 2023).*
- (10.36) Form of 2024 CEO RSU Award Agreement (incorporated by reference to [Exhibit 10.1 of the NiSource Inc. Form 8-K](#) filed on January 26, 2024).*
- (10.37) Form of 2024 CEO PSU Award Agreement (incorporated by reference to [Exhibit 10.2 of the NiSource Inc. Form 8-K](#) filed on January 26, 2024).*
- (10.38) Form of RSU Award Agreement (for awards on or after 2024) (incorporated by reference to [Exhibit 10.3 of the NiSource Inc. Form 8-K](#) filed on January 26, 2024).*
- (10.39) Form of PSU Award Agreement (for awards on or after 2024) (incorporated by reference to [Exhibit 10.48 to the NiSource Inc. Form 10-K](#) filed on February 22, 2023).*
- (10.40) [Form of 2025 CEO RSU Award Agreement.](#) * **
- (10.41) [Form 2025 CEO PSU Award Agreement.](#) * **
- (10.42) [Form of CEO RSU Award Agreement \(for awards on or after 2026\).](#) * **
- (10.43) [Form of CEO PSU Award Agreement \(for awards on or after 2026\).](#) * **
- (19.1) Securities Transaction Compliance Policy (incorporated by reference to [Exhibit 19.1 to the NiSource Inc. Form 10-K](#) filed on February 12, 2025) *
- (21) [List of Subsidiaries.](#)**
- (23) [Consent of Deloitte & Touche LLP.](#)**
- (31.1) [Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)**
- (31.2) [Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)**
- (32.1) [Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 \(furnished herewith\).](#)**
- (32.2) [Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 \(furnished herewith\).](#)**
- (97.1) NiSource Inc. Compensation Recoupment Policy (incorporated by reference to [Exhibit 97.1 to the NiSource Inc. Form 10-K](#) filed on February 12, 2025).*
- (101.INS) Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. **
- (101.SCH) Inline XBRL Schema Document.**
- (101.CAL) Inline XBRL Calculation Linkbase Document.**
- (101.LAB) Inline XBRL Labels Linkbase Document.**
- (101.PRE) Inline XBRL Presentation Linkbase Document.**
- (101.DEF) Inline XBRL Definition Linkbase Document.**
- (104) Cover page Interactive Data File (formatted as inline XBRL, and contained in Exhibit 101.)

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

NISOURCE INC.

*** Schedules and similar attachments to this Exhibit have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company agrees to furnish supplementally a copy of any omitted schedule or exhibit to the U.S. Securities and Exchange Commission (the "SEC") upon request.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

ITEM 16. FORM 10-K SUMMARY

None.

NiSOURCE INC.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

NiSource Inc.

(Registrant)

Date: February 11, 2026 By: /s/ LLOYD M. YATES
Lloyd M. Yates
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>/s/ LLOYD M. YATES</u> Lloyd M. Yates	President, Chief Executive Officer, and Director (Principal Executive Officer)	<u>Date: February 11, 2026</u>
<u>/s/ SHAWN ANDERSON</u> Shawn Anderson	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	<u>Date: February 11, 2026</u>
<u>/s/ GUNNAR J. GODE</u> Gunnar J. Gode	Senior Vice President, Chief Accounting & Tax Officer (Principal Accounting Officer)	<u>Date: February 11, 2026</u>
<u>/s/ KEVIN T. KABAT</u> Kevin T. Kabat	Chairman of the Board	<u>Date: February 11, 2026</u>
<u>/s/ PETER A. ALTABEF</u> Peter A. Altabef	Director	<u>Date: February 11, 2026</u>
<u>/s/ SONDRA L. BARBOUR</u> Sondra L. Barbour	Director	<u>Date: February 11, 2026</u>
<u>/s/ THEODORE H. BUNTING, JR.</u> Theodore H. Bunting, Jr.	Director	<u>Date: February 11, 2026</u>
<u>/s/ ERIC L. BUTLER</u> Eric L. Butler	Director	<u>Date: February 11, 2026</u>
<u>/s/ DEBORAH A. HENRETTA</u> Deborah A. Henretta	Director	<u>Date: February 11, 2026</u>
<u>/s/ DEBORAH A.P. HERSMAN</u> Deborah A. P. Hersman	Director	<u>Date: February 11, 2026</u>
<u>/s/ WILLIAM D. JOHNSON</u> William D. Johnson	Director	<u>Date: February 11, 2026</u>
<u>/s/ MICHAEL E. JESANIS</u> Michael E. Jesanis	Director	<u>Date: February 11, 2026</u>
<u>/s/ CASSANDRA S. LEE</u> Cassandra S. Lee	Director	<u>Date: February 11, 2026</u>
<u>/s/ JOHN MCAVOY</u> John McAvoy	Director	<u>Date: February 11, 2026</u>

NiSource

POLICY SUBJECT: Executive Severance Policy

EFFECTIVE DATE: January 1, 2026

REVISED: January 1, 2026

- Purpose. NiSource Inc. (“NiSource”) originally established this policy in June 2002 to provide severance benefits to certain terminated employees of NiSource and its subsidiaries or affiliate entities (the “Company”) (as amended and restated, hereinafter referred to as the “Policy”). Benefits under this Policy shall be in lieu of any benefits available under the NiSource General Severance Policy or any other severance plan, program or policy maintained by the Company, (e.g., a Voluntary Separation Program). For employees that have a Change in Control and Termination Agreement with NiSource (“CIC Agreement”), no benefit will be payable under the Policy if the relevant termination of employment results in eligibility for a payment under the CIC agreement. The Policy was amended and restated effective October 19, 2020, and amended January 1, 2026.
 - Administration. The Policy is administered by the Compensation and Human Capital Committee of the Board of Directors of NiSource or its successor (“Committee”). The Committee has complete discretion and authority with respect to the Policy and its application. The Committee reserves the right to interpret, prescribe, amend, and rescind rules and regulations relating to the Policy, determine the terms and provisions of severance benefits and make all other determinations it deems necessary or advisable for the administration of the Policy. The determination of the Committee in all matters regarding the Policy shall be conclusive and binding on all persons. The Committee hereby delegates to the Chief Human Resources Officer (the “CHRO”), or his or her delegate, the authority to develop and implement administrative guidelines regarding the operation of the Policy and render decisions on initial claims for benefits under the Policy.
 - Scope. The Policy will apply to all full-time or part-time regular, non-union employees of the Company whose job level, as established by the Company, is level B2 (or its equivalent) or above (“Participants”), which includes employees of each of its subsidiaries or affiliated entities (collectively, “Affiliates” and each an “Affiliate”). For the purposes of this Policy, the determination of whether an individual is a full-time or part-time employee of an Affiliate shall be made pursuant to the normal practices and policies of such Affiliate. The job level B2 generally equates to a short-term incentive
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target of 40% or more. For purposes of this policy, the job level, and not the short-term incentive target, will control.

4. Eligibility for Severance Pay. A Participant becomes eligible to receive severance pay (“Severance Pay”) only if he or she is terminated by the Company for any of the following reasons, provided that such termination event constitutes a “separation from service” as defined under Section 409A of the Internal Revenue Code of 1986, as amended, and applicable guidance thereunder (“Code Section 409A”), and further provided the conditions described in Section 5 below are met:
- (a) The Participant’s position is eliminated due to a reduction in force or other restructuring.
 - (b) The Participant’s position is moved to a principal employment location outside of a 50-mile radius from the Participant’s principal employment location on the date of termination of employment and such move would result in the Participant having a commute more than 20 miles longer, and provided that the Participant chooses not to relocate to the new location for such position, and such events are considered a “good reason” termination under Code Section 409A.
 - (c) The Participant’s employment is constructively terminated. Constructive termination shall be defined in a manner consistent with the guidance for a “good reason” termination under Code Section 409A, and means (1) the scope of the Participant’s position is changed materially (other than in the case of a rotational assignment or its equivalent) or (2) the Participant’s base pay is reduced by a material amount or (3) the Participant’s opportunity to earn a bonus under any Company short-term cash incentive compensation plan is materially reduced or is eliminated, and, in any such event, the Participant chooses not to remain employed in such position. If a Participant does not assert constructive termination within 14 days of being informed of a change described in (1), (2) or (3) above, in a written instrument delivered to the CHRO, such change will not be deemed a constructive termination. Following any such notice from the Participant, the Company shall have 30 days to cure the change that gives rise to constructive termination and, if uncured during such 30-day period, the Participant must terminate his or her employment within 30 days following the expiration of the 30-day cure period. The decision as to whether such a change constitutes constructive termination shall be made by the Committee or its delegate, not the Participant. If the Participant disagrees, the Participant must follow the claims procedure set forth in Section 15.
5. Conditions to Receipt of Benefits.
- (a) Severance Pay is not available to a Participant otherwise eligible for Severance Pay who transfers to another position within the Company.

- (b) Severance Pay is not available to a Participant whose position is eliminated due to (1) the sale of the Affiliate or assets of the Affiliate which employs the Participant on the date of termination or (2) the outsourcing of work, where in either such event the purchaser of the Affiliate or assets of the Affiliate or the outsourcing service provider makes an offer of employment to the Participant that, if it were the Company, would not constitute “constructive termination” as described in Section 4(c).
 - (c) Severance Pay is not available to a Participant whose position is eliminated due to the spin-off of any Affiliate, if the spun-off entity makes an offer of employment to the Participant that, if it were an Affiliate making such an offer, would not constitute “constructive termination” as described in Section 4(c).
 - (d) A Participant must execute and not revoke the release described in Section 6 below.
 - (e) During the statutory consideration period under any severance agreement or release described in Section 6, or during such other period as is otherwise agreed to by the Company and the Participant, he or she may be required to complete unfinished business projects and be available for discussions regarding matters relative to the Participant’s duties.
 - (f) A Participant must return all Company property and information.
 - (g) A Participant must agree to pay all outstanding amounts owed to the Company and authorize the withholding of any outstanding amounts owed from his or her final paycheck and/or Severance Pay.
6. Amount of Severance Pay. The amount of Severance Pay to which a Participant is eligible to receive under the Policy is 52 weeks of base salary at the rate in effect on the date of termination but excluding the impact of any reduction in base salary giving rise to a constructive termination event under clause (2) of Section 4(c).

Subject to Code Section 409A, a Participant who is receiving benefits under a short term disability plan will be eligible for Severance Pay at the end of the period of payment of short term disability if, and only if, (1) he or she is not then eligible for benefits under a long term disability plan, (2) he or she has been given medical release or approval to work again, and (3) he or she is not offered employment with the Company that, in the discretion of the Committee, is comparable to that held by the Participant at the time the applicable period of short term disability commenced. A Participant will not be eligible for Severance Pay at the end of the period of payment of long-term disability.

Severance Pay will be paid to a Participant in one lump sum cash payment as soon as practicable after the date of the Participant’s termination of employment, but in no event later than the 15th day of the 3rd month after such date, provided that the Participant has

executed a valid release of the Company and its respective officers, directors and employees, from any and all actions, suits, proceedings, claims and demands relating to the Participant's employment and the termination thereof, and the applicable revocation period has expired within this period, with such release becoming effective during the time period specified in the release but not no later than 60 days following the Participant's employment termination date. Severance Pay shall be reduced by applicable amounts necessary to comply with federal, state and local income tax withholding requirements.

A Participant eligible for Severance Pay pursuant to this Policy may seek other employment with the Company. The time period to seek other employment will run concurrently with any statutory period of consideration to execute a severance agreement or a release and will not exceed 45 days. If a Participant accepts other employment with the Company, such Participant shall not receive Severance Pay as provided by Section 5(a).

7. Benefits.

(a) Welfare Benefits. A Participant eligible for Severance Pay shall be eligible to receive, at the time of payment of Severance Pay, a lump sum payment equivalent to 130% of 52-weeks of COBRA (as defined in Section 4980B of the Internal Revenue Code of 1986, as amended, and Sections 601-609 of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), or any successor sections) continuation coverage premiums for the medical, dental, and vision coverage in which the Participant was enrolled immediately before his or her employment end date. Receipt of this lump sum payment does not constitute election of, or enrollment in, COBRA continuation coverage. To elect COBRA continuation coverage, a Participant must follow the enrollment instructions included in the COBRA election notice that such Participant receives shortly after the date of the Participant's termination of employment.

(b) Outplacement Services. A Participant eligible for Severance Pay shall be eligible to receive outplacement services as selected by the Company at its expense, for a period commencing on the date of termination of employment and continuing until the earlier to occur of the Participant accepting other employment or 12 months thereafter.

8. No Re-employment. A Participant who receives benefits pursuant to the Policy shall not be eligible for re-employment, unless the Committee or its delegate provides the Participant with a written waiver of this Section.

9. Independent Contractor Status. A Participant who receives benefits pursuant to the Policy shall not be eligible at any time after termination of employment to enter into a

consulting or independent contractor relationship with the Company pursuant to which relationship he or she shall perform the same or similar services, upon the same or similar terms and conditions, as were applicable to such Participant on the date of termination of employment, unless the Committee or its delegate provides the Participant with a written waiver of this Section.

10. Death of Participant. If a Participant dies prior to receiving Severance Pay and the benefits set forth in Section 7(a) to which he or she is eligible under the Policy, payment will be made to the representative of his or her estate.

11. Amendment or Termination.

(a) The Policy may be amended or terminated by the Committee at any time during its term when, in its judgment, such amendment or termination is necessary or desirable. No such termination or amendment will affect the rights of any Participant who has terminated employment prior to such termination or amendment and who, based on such termination, is then eligible for Severance Pay or other benefits under the Policy at the time of such amendment or termination. No agent or other employee, other than an officer of the Company acting on behalf of the Committee, has the authority to change or waive any provision of the Policy.

(b) Any duties delegated by the Committee to a particular officer are hereby delegated to any successor officer who assumes the duties of that officer as part of a corporate function or business realignment.

(c) Severance benefits under the Policy are not intended to be a vested right.

12. Governing Law and Venue. The terms of the Policy shall, to the extent not preempted by applicable federal law, be governed by, and construed and enforced in accordance with, the laws of the State of Indiana, including all matters of construction, validity and performance. In order to benefit Participants under this Policy by establishing a uniform application of law with respect to the administration of the Plan, the provisions of this Section 12 shall apply. Any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Policy shall be brought in any court of the State of Indiana and of the United States for the Northern District of Indiana. The Company, each Participant, and any related parties irrevocably and unconditionally consent to the exclusive jurisdiction of such courts in any such litigation related to this Policy and any transactions contemplated hereby. Such parties irrevocably and unconditionally waive any objection that venue is improper or that such litigation has been brought in an inconvenient forum.

13. Miscellaneous Provisions.

(a) Severance Pay and other benefits pursuant to the Policy shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge,

encumbrance or charge prior to actual receipt by a Participant, and any attempt to so anticipate, alienate, sell, transfer, assign, pledge, encumber or charge prior to such receipt shall be void and the Company shall not be liable in any manner for, or subject to, the debts, contracts, liabilities, engagements or torts, of any person eligible for any Severance Pay or other benefits under the Policy.

- (b) Nothing contained in the Policy shall confer upon any individual the right to be retained in the service of the Company, nor limit the Company's right to discharge or otherwise deal with any individual without regard to the existence of the Policy.
- (c) The Policy shall at all times be entirely unfunded. No provision shall at any time be made with respect to segregating assets of the Company for payment of any Severance Pay or other benefits hereunder. No employee or any other person shall have any interest in any particular assets of the Company by reason of the right to receive Severance Pay or other benefits under the Policy, and any such employee or any other person shall have only the rights of a general unsecured creditor with respect to any rights under the Policy.

14. Claims Procedure. A claim for benefits under the Policy shall be submitted in writing to the CHRO, or his or her delegate at the address provided in Section 16. If a claim for benefits under the Policy by a Participant or his or her beneficiary is denied, either in whole or in part, the CHRO or his or her delegate, will let the claimant know in writing within 90 days. If the claimant does not hear within 90 days, the claimant may treat the claim as if it had been denied. A notice of a denial of a claim will refer to a specific reason or reasons for the denial of the claim; will have specific references to the Policy provisions upon which the denial is based; will describe any additional material or information necessary for the claimant to perfect the claim and explain why such material information is necessary; and will have an explanation of the Policy's review procedure.

The claimant will have 60 days after the date of the denial to ask for a review and a hearing. The claimant must file a written request with the Committee for a review. During this time the claimant may review pertinent documents and may submit issues and comments in writing. The Participant will be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to his or her claim for benefits. The Committee will have another 60 days in which to consider the claimant's request for review. If special circumstances require an extension of time for processing, the Committee may have an additional 60 days to answer the claimant. The claimant will receive a written notice if the extra days are needed. The claimant may submit in writing any document, issues and comments he or she may wish. The decision of the Committee will tell the claimant the specific reasons for its actions, and refer the claimant to the specific Policy provisions upon which its decision is based. If the decision on review is not furnished within the time period set forth above, the claim shall be deemed denied on review.

If such determination is favorable to the claimant, it shall be binding and conclusive. If such determination is adverse to such claimant, it shall be binding and conclusive unless the claimant or his or her duly authorized representative notifies the Committee within 90 days after the mailing or delivery to the claimant by the Committee of its determination that claimant intends to institute legal proceedings challenging the determination of the Committee and actually institutes such legal proceedings within 180 days after such mailing or delivery

15. Rights Under ERISA. Each Participant in the Policy is entitled to certain rights and protection under the ERISA. ERISA provides that all Participants shall be entitled to:
- (a) Examine, without charge, at the Company's office all documents governing the Policy, and a copy of the latest annual report (Form 5500 Series) filed with the U.S. Department of Labor and available at the Public Disclosure Room of the Employee Benefits Security Administration.
 - (b) Obtain copies of all documents governing the operation of the Policy and copies of the latest annual report (Form 5500 Series) upon written request to the Committee. The Company may make a reasonable charge for the copies.
 - (c) Receive a summary of the Policy's annual financial report. The Committee is required by law to furnish each Participant with a copy of the summary annual report.

In addition to creating rights for Participants, ERISA imposes duties upon the people who are responsible for the operation of an employee benefit plan. The people who operate the Policy, called "fiduciaries" of the Policy, have a duty to do so prudently and in the interest of the Participants and beneficiaries. No one, including the Company, may fire a Participant or otherwise discriminate against a Participant in any way to prevent him or her from obtaining a benefit or exercising his or her rights under ERISA, if a Participant's claim for a benefit is denied in whole or in part, he or she must receive a written explanation of the reason for the denial. A Participant has the right to have the Committee review and reconsider his or her claim. Under ERISA, there are steps a Participant can take to enforce the above rights. For instance, if a Participant requests from the Committee a copy of the Policy or the latest annual report and does not receive either within thirty (30) days, he or she may file suit in a federal court. In such a case the court may require the Committee to provide the materials and pay the Participant up to \$110 a day until the Participant receives the materials, unless the materials were not sent because of reasons beyond the control of the Committee. If a Participant has a claim for benefits, which is denied or ignored, in whole or in part, and if the claims procedures under the Policy have been exhausted, he or she may file suit in a state or federal court. If a Participant is discriminated against for asserting his or her rights, he or she may ask assistance from the United States Department of Labor, or he or she may file suit in a federal court. The court will decide who should pay the court costs and legal fees. If the Participant is successful, the court may order the person he or she has sued to pay these

costs and fees. If the Participant loses, the court may order him or her to pay these costs and fees, for example, if it finds his or her claim to be frivolous. If a Participant has questions about the Policy, he or she should contact the Committee. If a Participant has any questions about this statement or about his or her rights under ERISA, he or she should contact the nearest office of the Employee Benefits Security Administration, U.S. Department of Labor (listed in your telephone directory), or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue N.W., Washington, D.C. 20210. A Participant may also obtain certain publications about his or her rights and responsibilities under ERISA by calling the publications hotline of the Employee Benefits Security Administration.

17. Policy Facts.

Plan Sponsor: Address:	NiSource Inc. 801 E, 86th Avenue Merrillville, Indiana 46410		
Plan Name:	NiSource Executive Severance Policy (for Employee Job Level B2 and above)		
Plan Number	537	537	537
Type of Plan:	Severance Policy-Welfare Benefits Plan		
Type of Administration	Self-Administered		
Policy Year:	Calendar year		
Employer Identification Number (EIN):	35-2108964		
Policy Administrator:	Compensation and Human Capital Committee of the Board of Directors of NiSource Inc.		
Business Address and Phone Number:	801 E. 86th Avenue Merrillville, Indiana 46410 877-647-5990		
Agent for Service of Legal Process:	Chief Human Resource Officer		
(Address)	801 E. 86th Avenue Merrillville, Indiana 46410		
Service of legal process may also be made upon the Compensation and Human Capital Committee of the Board of Directors of NiSource Inc.			

18. Code Section 409A.

The payments to the Participants pursuant to this Policy are intended to be exempt from Code Section 409A to the maximum extent possible, under either the separation pay exemption pursuant to Treasury regulation §1.409A-1(b)(9)(iii) or as short-term deferrals pursuant to Treasury regulation §1.409A-1(b)(4), and each payment hereunder shall be considered a separate payment.

AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT
OF
GENERATION
HOLDINGS II LLC

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AMENDED & RESTATED
LIMITED LIABILITY COMPANY AGREEMENT

This AMENDED & RESTATED LIMITED LIABILITY COMPANY AGREEMENT (this “Agreement”) of Generation Holdings II LLC, a Delaware limited liability company (the “Company”) is made and entered into as of October 28, 2025 (the “Effective Date”), by and among the Company, Generation Holdings I LLC, an Indiana limited liability company (the “NiSource Member”), BIP Orion Holdco L.P., a Delaware limited partnership (the “BIP Investor Member”), BIP Orion Holdco II L.P., a Delaware limited partnership (the “VCOC Investor Member”) and together with the BIP Investor Member, the “Investor Members”), and solely for the purposes of Article VI, NiSource Inc., a Delaware corporation (the “Parent”). The Company, the NiSource Member, the BIP Investor Member, and the VCOC Investor Member are each sometimes referred to herein as a “Party” and, together, as the “Parties”.

RECITALS

1. On September 3, 2025, the NiSource Member formed the Company as a wholly-owned subsidiary of the NiSource Member.
2. On December 24, 2024, NIPSCO Holdings II LLC, a Delaware limited liability company and an indirect Subsidiary of the Parent (“NHII”) formed NIPSCO Generation LLC, an Indiana limited liability company (“GenCo”).
3. On September 17, 2025, the NiSource Member, the Parent, NHII, and certain Subsidiaries of the Parent completed an internal restructuring resulting in GenCo becoming a wholly-owned, direct Subsidiary of the Company.
4. On or prior to the Effective Date, the NiSource Member contributed assets to the Company with a Gross Asset Value equal to \$176,640,114.11.
5. Substantially concurrently with the Effective Date, but in no event later than two (2) Business Days from the date hereof, (a) (i) the BIP Investor Member contributed that certain cash contribution in an amount equal to \$27,192,862.37 (the “BIP Investor Initial Contribution”) and (ii) the VCOC Investor Member contributed that certain cash contribution in an amount equal to \$7,958,520.34 (the “VCOC Investor Initial Contribution”, and collectively, the “Investor Initial Contribution”) and (b) the Company distributed an amount equal to 100% of the Investor Initial Contribution to the NiSource Member.
6. In exchange for the BIP Investor Initial Contribution, the Company issued to the BIP Investor Member Membership Interests constituting a 15.3945% Percentage Interest.
7. In exchange for the VCOC Investor Initial Contribution, the Company issued to the VCOC Investor Member Membership Interests constituting a 4.5055% Percentage Interest.
8. Upon the execution and delivery of this Agreement, the NiSource Member will own Membership Interests constituting an 80.1% Percentage Interest, and the Investor Members will own, in the aggregate, a 19.9% Percentage Interest. The Parties collectively will own 100% of the Membership Interests.
9. The Parties desire to, and by the execution and delivery of this Agreement hereby do, amend and restate in its entirety the Limited Liability Company Agreement of the Company, dated as of the date hereof, in order to provide for, among other things, the admission of the Investor Members, the rights and responsibilities of the Parties with respect to the governance, financing and operation of the Company, and certain other matters relating to the business arrangements between the Parties with respect to the Company.

Therefore, in consideration of the mutual covenants and agreements contained in this Agreement and other good and valid consideration the receipt of which is hereby acknowledged by each Party, and intending to be legally bound hereby, the Parties hereby agree as follows:

Article I GENERAL MATTERS

Section 1.1 Formation. The Parent formed the Company as a limited liability company pursuant to the Act. The Members ratify the organization and formation of the Company and continue the Company, pursuant to the terms and conditions of this Agreement.

Section 1.2 Name. The name of the Company is "Generation Holdings II LLC".

Section 1.3 Purpose.

(a) The purpose of the Company is to, either on its own behalf or through its Subsidiaries, engage in all lawful business for which limited liability companies may be formed under the Act in furtherance of the following activities as permitted by or in support of the GenCo Declination and/or otherwise consistent with applicable Law at such time, including any applicable IURC rules and regulations (the "Company Business"):

(i) owning and operating a public utility engaged in the generation, marketing and sale of electricity, storage, capacity and other ancillary products thereto;

(ii) making direct or indirect investments in, or purchasing, developing, financing, constructing, commercializing, owning, operating or maintaining assets and facilities relating to the generation and sale of electricity, storage, capacity and other ancillary products thereto;

(iii) undertaking any business activities conducted as of the Effective Date by the Company or its Subsidiaries;

(iv) engaging in such other activities that (A) support any GenCo Offtake Agreement or (B) are permitted by or are in support of the the GenCo Declination; or

(v) engaging in such other activities that the Board deems necessary, convenient or incidental to the conduct, promotion or attainment of the activities described in the foregoing subclauses (i), (ii), (iii) and (iv).

(b) The Company shall not engage in any activity or conduct inconsistent with the Company Business or any reasonable extensions thereof.

Section 1.4 Registered Office. The address of the registered office of the Company in the State of Delaware is 251 Little Falls Drive, Wilmington Delaware, 19808.

Section 1.5 Registered Agent. The name of the registered agent of the Company for service of process on the Company in the State of Delaware is Corporation Service Company.

Section 1.6 Members.

(a) The NiSource Member and each Investor Member is hereby or was heretofore admitted to the Company as a Member, and hereby continues as such. Unless admitted to the Company as a Member as provided in this Agreement, no Person shall be, in fact or for any other purpose, a Member.

(b) No Member shall have any right to withdraw from the Company except as expressly set forth herein. No Membership Interest is redeemable or repurchasable by the Company at the option of a Member. Except as expressly set forth in this Agreement, no event affecting a Member (including dissolution, bankruptcy or insolvency) shall affect its obligations under this Agreement or affect the Company.

(c) The Members' names, addresses and Percentage Interests are set forth on the Schedule of Members attached to this Agreement as Schedule 1.

(d) No Member, acting in its capacity as a Member, shall be entitled to vote on any matter relating to the Company other than as specifically required by the Act or as expressly set forth in this Agreement.

(e) Except as otherwise expressly set forth in this Agreement, any matter requiring the action, consent, vote or other approval of the Members hereunder shall require action, consent, vote or approval of the Members owning at least a majority of the Membership Interests. Except as otherwise expressly set forth in this Agreement, the VCOC Investor Member hereby irrevocably makes, constitutes and appoints the BIP Investor Member as the VCOC Investor Member's true and lawful attorney-in-fact, with full power of substitution, to act, consent or otherwise approve any matter requiring action, consent or other approval by the VCOC Investor Member in such forms and on such terms and conditions as the BIP Investor Member may deem necessary or desirable. In addition, except as otherwise expressly set forth in this Agreement, the BIP Investor Member shall have the right and power to vote, and VCOC Investor Member grants to the BIP Investor Member its irrevocable proxy to vote, Membership Interests owned by the VCOC Investor Member, together with the Membership Interests owned by BIP Investor Member, with respect to, any matter requiring the consent, vote or other approval of the 19.9% Membership Interest held by the Investor Members, collectively. The execution of any documents by the BIP Investor Member on behalf of the VCOC Investor Member shall be conclusive evidence of its authority as attorney-in-fact or as the holder of the irrevocable proxy for the VCOC Investor Member and generally to act, consent, vote or otherwise approve any matter requiring the action, consent, vote or other approval of the Members under this Agreement. The VCOC Investor Member acknowledges the appointment of the BIP Investor Member as its attorney-in-fact and agrees that the appointment of the BIP Investor Member as its attorney-in-fact and the grant of the irrevocable proxy to the BIP Investor Member under this Section 1.6(e) is coupled with an interest and may not be revoked and will survive insolvency or bankruptcy of the VCOC Investor Member. The BIP Investor Member accepts its appointment and authorization to act as attorney-in-fact and as proxy holder for the VCOC Investor Member. Except as otherwise expressly set forth in this Agreement, the power and authority granted under this Section 1.6(e) will be exclusive.

(f) A Member shall automatically cease to be a Member upon Transfer of all of such Member's Membership Interests made pursuant to and in accordance with the terms of this Agreement. Immediately upon any such permissible Transfer, the Company shall cause such Member to be removed from Schedule 1 to this Agreement and to be substituted by the transferee or transferees in such Transfer, and, except as otherwise expressly provided for herein, such transferee or transferees shall be deemed to be a "Party" for all purposes hereunder and all references to the NiSource Member, the BIP Investor Member, or the VCOC Investor Member, as the case may be, shall be deemed to be references to such transferee or transferees (notwithstanding, in the case that more than one Person is a transferee of such Membership Interests, that such defined terms as used herein are singular in number).

Section 1.7 Powers. The Company shall have the power and authority to do any and all acts necessary or convenient to or in furtherance of the purposes described in Section 1.3, including all power and authority, statutory or otherwise, possessed by, or which may be conferred upon, limited liability companies under the Laws of the State of Delaware.

Section 1.8 Limited Liability Company Agreement. This Agreement shall constitute the "limited liability company agreement" of the Company for the purposes of the Act. The rights, powers, duties, obligations and liabilities of the Members shall be determined pursuant to the Act and this Agreement. To the extent that the rights, powers, duties, obligations and liabilities of any Member are different by reason of any provision of this Agreement than they would be under the Act in the absence of such provision, this Agreement shall control to the fullest extent permitted by the Act and other applicable Law.

Section 1.9 Issuance of Additional Membership Interests. Except for (a) the issuance of any Excluded Membership Interests or (b) the issuance of Membership Interests made pursuant to and in accordance with Section 5.1(c), Article VII, or as otherwise permitted herein, the Company shall not issue any new Membership Interests, or any securities convertible into Membership Interests or other Equity Interests of the Company, to any Third Party or to the Members other than in accordance with their respective Percentage Interests.

Section 1.10 No State Law Partnership. The Members intend that the Company not be a partnership (including a limited partnership) or joint venture, and that no Member be a partner or joint

venturer of any other Member by virtue of this Agreement, for any purposes, and neither this Agreement nor any other document entered into by the Company or any Member relating to the subject matter hereof shall be construed to suggest otherwise. Nothing in this Section 1.10 shall control with respect to income tax treatment of the Company.

Article II MANAGEMENT

Section 2.1 Directors. Subject to the provisions of the Act and any limitations in this Agreement as to action required to be authorized or approved by the Members, the business and affairs of the Company shall be managed and all its powers shall be exercised by or under the direction of a board of directors (the "Board") and each duly appointed and continuing member thereof from time to time, a "Director"), and no Member, by virtue of having the status of a Member, shall have any management power over the business and affairs of the Company or any actual or apparent authority to enter into Contracts on behalf of, or to otherwise bind, the Company. Without prejudice to such general powers, but subject to the same limitations, the Board shall be empowered to conduct, manage and control the business and affairs of the Company and to make such rules and regulations therefor not inconsistent with applicable Law or this Agreement, as the Board shall deem to be in the best interest of the Company. Each Director is hereby designated as a "manager" of the Company within the meaning of Section 18-101 of the Act.

Section 2.2 Number of Directors; Proportional Appointment Rights.

(a) The authorized number of Directors constituting the Board shall be seven (7) Directors (the "Total Number of Directors").

(b) The BIP Investor Member shall, as of the Effective Date, be entitled to appoint two (2) Directors, and the BIP Investor Member shall retain the right to appoint at least two (2) Directors for so long as the Investor Members collectively hold at least a 17.5% Percentage Interest in the aggregate. In the event that the Investor Members' aggregate Percentage Interest is reduced below 17.5% but remains at or above a 9.9% Percentage Interest, the BIP Investor Member shall retain the right to appoint one (1) Director. In the event that the Investor Members' aggregate Percentage Interest is reduced below 9.9%, the BIP Investor Member shall cease to be entitled to appoint a Director. Any Directors appointed by the BIP Investor Member are referred to herein as "Investor Directors". The appointment of any particular proposed Investor Director shall be subject to the NiSource Member's prior written consent of the identity of such individual prior to his or her appointment to the Board; provided however, that the NiSource Member shall not have any consent right over the appointment of a proposed Investor Director that is a Qualified Designee.

(c) In the event that the Investor Members' aggregate Percentage Interest decreases below 17.5% or 9.9%, as applicable, if the BIP Investor Member fails to remove an Investor Director concurrently with such decrease in the Investor Members' aggregate Percentage Interest to be in compliance with the BIP Investor Member's Director appointment rights set forth in Section 2.2(b), then the NiSource Member may remove such appropriate number of Investor Directors from the Board such that the BIP Investor Member is in compliance with its Director appointment rights set forth in Section 2.2(b), such removal being effective immediately.

(d) The NiSource Member shall be entitled to appoint all of the remaining Total Number of Directors that the Investor Member is not entitled to appoint pursuant to Section 2.2(b). Directors appointed by the NiSource Member are referred to herein as "NiSource Directors"; provided, that any NiSource Director must be a Qualified Designee. The NiSource Member shall further be entitled to designate a NiSource Director to serve as the chairperson of the Board.

(e) For so long as the BIP Investor Member is entitled to appoint an Investor Director, the BIP Investor Member shall be further entitled to designate the Board Observer or any other individual (provided, that such designee is a Qualified Designee) (the "Designated Alternate") in its place and stead in the event that the Investor Director is unable to attend such meeting (or meetings of Board committees, if any pursuant to Section 2.12). The Designated Alternate will be entitled to exercise the powers of the Investor Director at such meetings, and will be subject to all of the responsibilities of an Investor Director hereunder at such meeting as if they were an Investor Director. The appointment of such Designated Alternate shall be subject to the same approval right of the NiSource Member applicable to the Investor

Director under Section 2.2(b). If the Designated Alternate is serving in lieu of the Investor Director at any Board or committee meeting, the BIP Investor Member shall provide written notice to the NiSource Member of this fact prior to the commencement of such meeting (which notice may be by way of an email to the NiSource Directors), and such notice shall be recorded in the minutes of such meeting. For the avoidance of doubt, any references to approval or notice by the Investor Director in this Agreement will be deemed to refer to the Investor Director, and not the Designated Alternate, except in respect of the voting on matters presented at the meeting at which the Designated Alternate is attending. In the event that the Designated Alternate is also a Board Observer, at any Board or committee meeting in which he or she is serving as the Investor Director pursuant to this Section 2.2(e), he or she shall be deemed to be serving only as an Investor Director and not as a Board Observer at such meeting.

Section 2.3 Removal of Directors. Any one or more Directors may be removed at any time, with or without cause, by the Member that appointed such Director, and except as provided in Section 2.2(c), may not be removed by any other means. If a Director is convicted by a court or equivalent tribunal of any felony (or equivalent crime in the applicable jurisdiction), or of any misdemeanor (or equivalent crime in the applicable jurisdiction) that involves financial dishonesty or moral turpitude, then the Member that appointed such Director shall, unless consented to by the NiSource Member in the case of an Investor Director and by the BIP Investor Member in the case of a NiSource Director, promptly remove such Director. Delivery of a written notice to the Company by a Member designating for removal of a Director appointed by such Member shall conclusively and with immediate effect constitute the removal of such Director, without the necessity of further action by the Company, the Board, or by the applicable removed Director. Each Director duly appointed by a Member pursuant to and in accordance with the provisions of Section 2.2 shall hold office until his or her resignation, death, permanent disability, removal pursuant to and in accordance with Section 2.2 or with this Section 2.3, or until a successor Director is duly appointed by the Member that appointed (and continues to be entitled to appoint) such Director.

Section 2.4 Vacancies. A vacancy shall be deemed to exist in case of the resignation, death, permanent disability or removal of any Director. The Member entitled to appoint a Director to the vacant directorship may appoint or elect a Director thereto to take office (a) immediately, (b) effective upon the departure of the vacating Director, in the case of a resignation, or (c) at such other later time as may be determined by such Member.

Section 2.5 Acts of the Board; Voting. Except as otherwise expressly set forth in this Agreement (including Section 8.1), a vote of a majority of the Directors present at a duly called and noticed meeting of the Board at which a quorum is present shall be required to authorize or approve any action of the Board. Every act of or decision taken or made by the Directors pursuant to the vote required by this Section 2.5 shall be conclusively regarded as an act of the Board.

Section 2.6 Compensation of Directors. The Board shall have the authority to fix the compensation of Directors for their service to the Company, if any. The Board shall reimburse the Directors for their respective reasonable, documented out-of-pocket expenses incurred for attendance at meetings of the Board consistent with the Company's then-applicable policies related to travel and expenses for directors or executive officers (or, if none exists, such travel and expense policies of Parent). Nothing herein shall be construed to preclude any Director from serving the Company or any of its Affiliates in any other capacity and receiving compensation therefor.

Section 2.7 Meetings of Directors; Monthly Meetings; Notice.

(a) **Board Meetings.** Except as provided pursuant to Section 2.10, meetings of the Board, both regular and special, for any purpose or purposes may be called at any time by the Board or by the Company at the request of any Director, by providing at least seven (7) calendar days' written notice to each Director unless the chairperson of the Board determines, acting reasonably, that there is a significant and time sensitive matter that requires shorter notice to be given, in which case a meeting of the Board may be called by giving at least forty-eight (48) hours' written notice to each Director. Regular Board meetings will be held quarterly. Each notice shall state the purpose(s) of and agenda (including any relevant presentation materials relating thereto) for the meeting and include all required information, including dial-in numbers or other applicable access information, in order to participate in the meeting by telephonic means, over the internet or by means of any other customary electronic communications equipment. Unless otherwise agreed by unanimous consent of the Board, no proposal shall be put to a vote of the Board unless it has been listed on the agenda for such meeting. Notice of the time and place of meetings shall be delivered personally or by telephone to each Director, or sent by e-mail or other electronic communication to any Director. Any notice given personally or by telephone shall be

communicated to the applicable Director. A Director may waive the notice requirement set forth in this Section 2.7 by any means reasonable in the circumstances, including by communication to one or more other Directors, and the presence of a Director at a meeting or the approval by a Director of the minutes thereof shall conclusively constitute a waiver by such Director of such notice requirement.

(b) Management Update Meetings. The Company shall have regular management meetings to update the Members (each, a “Management Update Meeting”) in such cadence and covering such matters as the officers shall determine in good faith, consistent with past practices of the other public utility Affiliates of the NiSource Member (including NHII); provided that such cadence and matters covered and manner thereof shall be adjusted to take into account the general nature of the Company Business. The management team shall circulate in advance of each such meeting (i) a presentation or other written materials reasonably detailing (a) financial results and operational key performance indicators for the prior period and (b) material developments since the prior meeting (as applicable to the Company’s stage of development, including providing any material progress reports provided to the Company by any engineering, procurement and construction contractors) and (ii), certain third-party reports (including for the avoidance of doubt, all such material third-party reports) prepared in connection with the Company Business in preparation for such Management Update Meeting. For so long as the Investor Members’ aggregate Percentage Interest is equal to or greater than the Investor Consent Threshold, and no Investor Member is a Defaulting Member, Representative(s) of the BIP Investor Member may attend, in an observational capacity, each Management Update Meeting, and the number of such attendees at such meetings may be reasonably restricted by the Company’s management team, consistent with past practices of the other public utility Affiliates of the NiSource Member (including NHII); provided, that all attendees shall be subject to customary confidentiality obligations and the terms with respect to sensitive materials set forth in Section 2.13 which are hereby incorporated by reference *mutatis mutandis*. The agenda and presentation materials for each Management Update Meeting shall be provided to attendees reasonably in advance of such Management Update Meeting. For the avoidance of doubt, this Section 2.7(b) shall not (i) confer any additional rights on any Investor Member with respect to the governance or operations of the Company and its Subsidiaries, other than the right to attend such Management Update Meeting in an observational capacity only, or (ii) restrict the officers or other members of the Company’s management team from meeting with the NiSource Member or its Affiliates outside of the context of the Management Update Meetings.

Section 2.8 Quorum.

(a) Except as otherwise expressly set forth herein, the presence (whether physical, telephonic, over the internet or by means of other customary electronic communications equipment) of a majority of the number of Directors then serving on the Board (without regard to the Total Number of Directors), including at least one Investor Director, at a meeting of the Board shall constitute a quorum of the Board for the transaction of all business thereat; provided, that if quorum fails at two (2) consecutive attempted meetings that are called pertaining to the same subject matter with proper notice due to the failure of the Investor Director(s) to attend, then at the third attempted meeting only a majority of the number of Directors then serving on the Board (without regard to the Total Number of Directors or the attendance of the Investor Director(s)) must be present in person, by telephone or other electronic means or by proxy in order to constitute a quorum for the transaction of business for purposes of conducting only those matters that were included on the agenda for the attempted meetings immediately preceding such third attempted meeting; provided, that, at least twenty-four (24) hours prior written notice of any rescheduled meeting is required to be provided to the other Directors.

(b) If a quorum is not present at any meeting of the Board, the Directors present at such meeting may adjourn the meeting, without notice other than announcement at the meeting.

Section 2.9 Place and Method of Meetings.

(a) Meetings of the Board may be held at any place, whether within or outside the State of Delaware or the State of Indiana, and meetings may be held, in whole or in part, by telephonic means, over the internet or by means of any other customary electronic communications equipment. The place at which (or, if applicable, the electronic communication methods by which) a meeting will be held may be specified in the applicable notice of the meeting.

(b) The Directors may participate in meetings of the Board by telephonic means, over the internet or by means of any other customary electronic communications equipment, and, to the fullest extent permitted by applicable Law, shall be deemed to be present at such meeting for all purposes, including for purposes of determining quorum and of voting.

Section 2.10 Action by the Board Without a Meeting. Any action required or permitted to be taken by the Board may be taken without a meeting if a number of Directors the vote of whom would be minimally necessary to approve such action at a meeting of the Board shall individually or collectively consent in writing to such action; provided, that in order for such consent to be effective it shall have been provided to all Directors at least forty-eight (48) hours prior to its stated effectiveness, unless such prior notice is waived in writing by the Directors taking any such written action which includes at least one (1) Investor Director. Notwithstanding the foregoing, no action set forth in Section 8.1 that requires the consent of the BIP Investor Member shall be effected by written action entered into pursuant to this Section 2.10 without the BIP Investor Member's written consent. Any written actions of the Board may be in counterparts and transmitted by e-mail and shall be filed with the minutes of the proceedings of the Board. Such written actions shall have the same force and effect as a vote of the Board.

Section 2.11 Duties of Directors. Other than as set forth in Section 9.3, each member of the Board shall have fiduciary duties identical to those of directors of a business corporation organized under the General Corporation Law of the State of Delaware and except to the extent not permitted by applicable Law, no member of the Board shall be personally liable to the Company or its Members for monetary damages for breach of its fiduciary duties in such capacity. The provisions of this Agreement, to the extent that they expand or restrict the duties and liabilities of the Board, otherwise existing at law or in equity, are agreed by the Members to replace such other duties and liabilities of the Board.

Section 2.12 Committees. The Board may create one or more committees of the Board, delegate responsibilities, duties and powers to such one or more committees, and appoint Directors to serve thereon. Each Director appointed to serve on any such committee shall serve at the pleasure of the Board, or otherwise in accordance with the terms of the resolution designating the applicable committee. Section 2.4, Section 2.7, Section 2.8, Section 2.9 and Section 2.10 shall each apply to any committee of the Board with the same terms applicable to the Board, *mutatis mutandis*. For each committee of the Board, the Board shall designate one Investor Director to serve on each such committee so long as the BIP Investor Member is entitled to appoint a Director pursuant to Section 2.2.

Section 2.13 Investor Member Board Observer. The BIP Investor Member shall be entitled to appoint one (1) Person (which shall be an individual) to serve as an observer of the Board (the "Board Observer") for so long (i) the BIP Investor Member is entitled to appoint only one (1) Investor Director, but in no event when the BIP Investor Member is entitled to appoint two (2) Investor Directors or (ii) the Investor Members' aggregate Percentage Interest is greater than or equal to 4.9% but in no event if the BIP Investor Member is entitled to appoint two (2) Directors, the identity of whom shall be subject to the prior written consent of the NiSource Member. The Board Observer shall have the right to receive notice of, attend and participate in all meetings of the Board (and any committee thereof) and to receive all information provided to Directors at the same time and in the same manner as provided to such Directors; provided, however, that the Company and the Board will be entitled to withhold access to any portion of the information and to exclude the Board Observer from any portion of any meeting of the Board (or any committee thereof) if the Company or the Board determines in good faith in reliance upon the advice of counsel that access to such information or attendance at such meeting (i) is reasonably necessary to preserve an attorney-client privilege of the Company or the Board or (ii) otherwise implicates any conflict of interest between any Investor Member, on the one hand, and a particular matter or transaction under consideration by the Board, on the other hand; provided, however, that the BIP Investor Member shall be notified of any intent to exclude the Board Observer in reliance on clause (ii) above in advance of any meeting from which the Board Observer is to be excluded to the extent reasonably practicable; provided, further, that, any Board Observer that is excluded shall only be excluded for such portion of the meeting during which such conflicted matter or transaction is being discussed. For the avoidance of doubt, the Board Observer shall not have any voting rights with respect to any matter brought before the Board and shall not be counted in any manner with respect to whether a quorum is present at a meeting of the Board, and (without limiting the Company's obligations to provide the Board Observer with notice of meetings of the Board and any committee thereof as set forth in this Section 2.13) no defect in the provision of notice to the Board Observer of any meeting of the Board shall be construed to constitute a defect in the provision of notice to Directors. The Board Observer shall be bound by the same confidentiality obligations as the Directors as set forth in Section 9.6. The BIP Investor Member may cause the Board

Observer to resign or appoint a replacement Board Observer from time to time by giving written notice to the Company. In the event that the Investor Members' aggregate Percentage Interest becomes less than 4.9%, the BIP Investor Member's rights under this Section 2.13 shall immediately cease. For the avoidance of doubt, the sole purpose of this Section 2.13 is to provide observation rights (subject to the limitations and conditions set forth in this Section 2.13) to an individual Representative of the BIP Investor Member, and in no event will any Board Observer be construed to be a third-party beneficiary of this Agreement, an agent of the Company of any kind or for any purpose, or have any other claim against the Company or the Members in relation to any matter whatsoever.

Section 2.14 Related Party Matters.

(a) The Parties acknowledge that certain Affiliates of the Company provide various services to the Company and its Subsidiaries and that all of such services shall continue in the ordinary course of business. All agreements between any member of the Outside Group, on the one hand, and the Company Group, on the other hand, (such transactions, "Affiliate Agreements"), shall be (i) entered into and carried out in a manner that, except as may be required by any applicable Law or Order, is (A) consistent with past practices and the corporate allocation and affiliate transaction policies of the Outside Group in effect at such time and (B) on terms and conditions that are pursuant to the corporate allocation policies and affiliate transaction policies of the Outside Group as of such time to the extent that they are non-discriminatory against the Company and its Subsidiaries and are generally consistent with the corporate allocation policies and affiliate transaction policies of the Outside Group, (ii) entered into and carried out in accordance with the requirements of any applicable Law or Order (including, for the avoidance of doubt, on such terms and conditions as may be required to obtain the approval of the applicable Governmental Body in respect of such transaction) and (iii) if applicable pursuant to Section 8.1, approved by the Board. Notwithstanding anything to the contrary in this Agreement, except as required by applicable Law, the NiSource Member shall ensure during the term of this Agreement that any methodologies used to allocate costs to the Company Group (i) are and will be consistently applied to other members of the Outside Group in a manner that does not have a disproportionate adverse impact on the Company or any of its Subsidiaries as compared to any member of the Outside Group and (ii) would not result in any fines or penalties that are imposed on any member of the Outside Group being allocated to the Company or any of its Subsidiaries. The NiSource Member shall also use commercially reasonable efforts to ensure corporate separateness from the NiSource Member and the other members of the Outside Group in a manner and consistent with the Company Group's and the Outside Group's respective past practices and applicable Law and Orders. The NiSource Member shall continue to audit its corporate services annually by its then current auditor in the ordinary course and shall share such audit with the BIP Investor Member (including any work papers and other supporting documentation reasonably requested by the BIP Investor Member (subject to its prior execution of a customary non-reliance letter agreement to the extent requested by such auditor)). Notwithstanding the foregoing, the Company will provide a copy of any Affiliate Agreement that is required to be filed with the IURC, to be entered into by the Company Group prior to such filing and will use commercially reasonable efforts to provide the BIP Investor with any material Affiliate Agreements to be entered into prior to such entry.

(b) Each Investor Member acknowledges and agrees that (i) the Company Group and the Outside Group prior to the Effective Date engaged in Affiliate Agreements, and continues to and will, pursuant to and in accordance with the provisions of Section 2.14(a), from and after the Effective Date engage in new Affiliate Agreements (including Genco Offtake Agreements), subject to the BIP Investor Member's approval rights under Section 8.1 (if applicable) and (ii) all services provided by any member of the Outside Group to any member of the Company Group as of the Effective Date shall or will remain outstanding and be payable in accordance with their terms or sooner as the Board determines in good faith is appropriate.

(c) In the event the Company and/or the NiSource Member becomes aware of any material breach or material default (it being understood that, for purposes of this clause (c), a breach or default will be deemed to be "material" if the reasonably expected amount of damages that would be sustained by the Company and its Affiliates as a result of such breach or default, or series of related breaches or defaults, would exceed \$100,000,000.00 in the aggregate, subject to an annual increase by the CPI Escalator) by any member of the Company Group or Outside Group under any Affiliate Agreement (an "Affiliate Agreement Default"), the Company and/or the NiSource Member, as applicable, shall promptly, but in any event within ten (10) Business Days after becoming aware of such Affiliate Agreement Default, send a written notice (an "Affiliate Agreement Default Notice") to the Company and the BIP Investor Member

setting forth in reasonable detail the nature of such Affiliate Agreement Default and the reasonable estimate of the current and future anticipated losses associated with such Affiliate Agreement Default (to the extent feasible to make a reasonable estimate at such time). After delivery of such Affiliate Agreement Default Notice to the BIP Investor Member, the Company (and, if the Company did not provide the Affiliate Agreement Default Notice, the NiSource Member) shall promptly provide the BIP Investor Member with any additional information reasonably requested by the BIP Investor Member and available to the NiSource Member relating to such Affiliate Agreement Default. The defaulting party under such Affiliate Agreement shall have (i) twenty (20) Business Days following the expiration of the applicable cure period in respect of such Affiliate Agreement, to fully cure any monetary Affiliate Agreement Default, and (ii) sixty (60) days following the expiration of the applicable cure period in respect of such Affiliate Agreement, to fully cure any non-monetary Affiliate Agreement Default, subject to and consistent with applicable Law and Orders, if capable of being cured. In the event that any material alleged Affiliate Agreement Default is not timely cured in accordance with the preceding sentence, the BIP Investor Member shall have the sole right to cause the Company and its Subsidiaries to take, or refrain from taking, any actions in connection with the enforcement of or compliance with the rights or obligations of the Company or any of its Subsidiaries under the terms of the applicable Affiliate Agreement. In addition to, and not in limitation of, the foregoing provisions of this Section 2.14(c), the Company shall notify the BIP Investor Member prior to, or within ten (10) days following, its execution of any new Affiliate Agreement or any material amendment to any Affiliate Agreement setting forth in reasonable detail the nature of such new Affiliate Agreement or such amendment and, upon request from the BIP Investor Member, shall provide copies of all Contracts relating to such new Affiliate Agreement or such amendment within five (5) Business Days of such request.

Article III OFFICERS

Section 3.1 Appointment and Tenure.

(a) The Board may, from time to time, designate officers of the Company to carry out the day-to-day business of the Company.

(b) The officers of the Company shall be comprised of one or more individuals designated from time to time by the Board. Each officer shall hold his or her office for such term and shall have such authority and exercise such powers and perform such duties as shall be determined from time to time by the Board. Any number of offices may be held by the same individual. The salaries or other compensation, if any, of the officers shall be fixed from time to time by the Directors.

(c) The officers of the Company may consist of a president, a secretary and a treasurer. The Board may also designate one or more vice presidents, assistant secretaries and assistant treasurers. The Board may designate such other officers and assistant officers and agents as the Board may deem necessary or appropriate.

Section 3.2 Removal. Any officer may be removed as such at any time by the Board, either with or without cause, in its discretion, subject to the consultation right of the BIP Investor Member set forth in Section 8.2.

Section 3.3 President. The president, if one is designated, shall be the chief executive officer of the Company, shall have general and active management of the day-to-day business and affairs of the Company as authorized from time to time by the Board, and shall be authorized and directed to implement all actions, resolutions, initiatives and business plans adopted by the Board.

Section 3.4 Vice Presidents. The vice presidents, if any are designated, in the order of their election, unless otherwise determined by the Board, shall, in the absence or disability of the president, perform the duties and have the authority and exercise the powers of the president. They shall perform such other duties and have such other authority and powers as the Board may from time to time prescribe.

Section 3.5 Secretary; Assistant Secretaries. The secretary, if one is designated, shall perform such duties and have such powers as the Board may from time to time prescribe. The assistant secretaries, if any are designated, and unless otherwise determined by the Board, shall, in the absence or disability of the secretary, perform the duties and exercise the powers of the Secretary. They shall perform such other duties and have such other powers as the Board may from time to time prescribe.

Section 3.6 Treasurer; Assistant Treasurers. The treasurer, if one is designated, shall have custody of the Company's funds and securities and shall keep full and accurate accounts and records of receipts, disbursements and other transactions in books belonging to the Company, and shall deposit all moneys and other valuable effects in the name and to the credit of the Company in such depositories as may be designated from time to time by the Board. The treasurer shall disburse the funds of the Company as may be ordered by the Board, taking proper vouchers for such disbursements, and shall render the president and the Board, when so directed, an account of all of his or her transactions as treasurer and of the financial condition of the Company. The treasurer shall perform such other duties and have such other powers as the Board may from time to time prescribe. If required by the Board, the treasurer shall give the Company a bond of such type, character and amount as the Board may require. The assistant treasurers, if any are designated, unless otherwise determined by the Board, shall, in the absence or disability of the treasurer, perform the duties and exercise the powers of the treasurer. They shall perform such other duties and have such other powers as the Board may from time to time prescribe.

Section 3.7 Duties of Officers. Other than as set forth in Section 9.3 with respect to any Representative of Parent or its Affiliates who is also an officer of the Company, each officer of the Company (in such individual's capacity as an officer) will owe the Company, its Subsidiaries and the Members such fiduciary duties that apply to officers of a Delaware corporation. No provision of this Agreement will be deemed to limit or eliminate such fiduciary duties.

Article IV DEFAULT; DISSOLUTION

Section 4.1 Events of Default. The following shall constitute events of default (each, an "Event of Default") by the applicable Member under this Agreement:

- (a) any material breach of this Agreement by such Member;
- (b) any failure by such Member to make any Mandatory Capital Contribution pursuant to and in accordance with a Capital Request Notice issued pursuant to Section 5.1 or, with respect to an Additional Funding Requirement (as defined in Section 5.1) (other than a Mandatory Capital Contribution), a duly authorized officer of each of the Investor Members has affirmed in writing that such Investor Member would make such Additional Funding Requirement in its Response to Capital Call but failed to do so within the time period set forth in Section 5.1, in any case any such failure to fund by any Investor Member shall be deemed to be a failure to fund by all of the Investor Members;
- (c) any purported Transfer by such Member made other than pursuant to and in accordance with the terms and conditions of this Agreement;
- (d) any Event of Default (as defined in the NHII Operating Agreement) under the NHII Operating Agreement by a NHII Member which is an Affiliated NHII Member (which remains uncured after any applicable notice or cure period as provided therein including, for the avoidance of doubt, pursuant to Section 4.2 thereof); or
- (e) the filing of a petition seeking relief, or the consent to the entry of a decree or Order for relief in an involuntary case, under the bankruptcy, rearrangement, reorganization or other debtor relief Laws of the United States or any state or any other competent jurisdiction or a general assignment for the benefit of its creditors by such Member or by any of its controlling Affiliates.

Section 4.2 Default Notice. If an Event of Default occurs, then any Member (other than the Defaulting Member) may deliver to the Company and to the Member subject to the Event of Default, including for the avoidance of doubt, any Event of Default (as defined in the NHII Operating Agreement) under the NHII Operating Agreement (the "Defaulting Member"; provided, that at any time the Defaulting Member is an Investor Member, then both Investor Members shall be deemed Defaulting Members until such Investor Member ceases to be a Defaulting Member according to the terms of this Agreement) a notice of the occurrence of such Event of Default, setting forth the circumstances of such Event of Default. If, within thirty (30) days following the delivery of such notice (or, with respect to an Event of Default set forth in Section 4.1(b), ten (10) days), the Defaulting Member has not cured the event giving rise to the Event of Default (if capable of being so cured), the provisions of this Agreement applicable to a "Defaulting Member" shall apply to such Defaulting Member and, in addition to any other rights and remedies provided under this Agreement, (i) if the Defaulting Member is an Investor Member,

the Defaulting Member's voting rights, including its approval rights in Section 8.1, shall be suspended and (ii) any net Available Cash required to be distributed to the Defaulting Member shall instead be distributed to the non-Defaulting Members, or the Company, as applicable, if such breach is capable of being cured by the payment of such amounts which such clauses (i) and (ii) shall apply as applicable (and such Member shall be considered a "Defaulting Member") until the applicable Event of Default and the material effects thereof have been cured (if capable of being so cured).

Section 4.3 Dissolution.

(a) Subject to obtaining the requisite authorization, approval or consent of any Governmental Body, the Company shall dissolve, and its affairs shall be wound up, upon either (i) the approval by the Board and the written consent of all of the Members or (ii) the entry of a decree of judicial dissolution under Section 18-802 of the Act (each, an "Event of Dissolution").

(b) Upon the occurrence of an Event of Dissolution, the Company will continue solely for the purposes of winding up its affairs in an orderly manner, liquidating its assets and satisfying the claims of its creditors and the Members. No Member, acting in its capacity as such, will take any action that is inconsistent with, or not necessary to or appropriate for, the winding up of the Company's business and affairs. All covenants contained and obligations provided for in this Agreement will continue to be fully binding upon the Members until such time as the property of the Company has been distributed pursuant to Section 5.3 and the certificate of formation of the Company has been canceled pursuant to the Act.

(c) After the occurrence of an Event of Dissolution, and after all of the Company's debts, liabilities and obligations have been paid and discharged or adequate reserves have been made therefor and all of the remaining assets of the Company have been distributed to the Members, the Company shall make necessary resolutions and filings to dissolve the Company under the Act.

Article V
CAPITAL CONTRIBUTIONS; DISTRIBUTIONS; ALLOCATIONS

Section 5.1 Capital Contributions.

(a) If the Board determines that it is in the best interests of the Company to obtain additional equity capital for purposes of (i) developing, acquiring or maintaining Qualifying Core Assets or funding ordinary course operations of the Company Business (including with respect to any GenCo Offtake Agreement), (ii) satisfying the Company's or any of its Subsidiary's obligations to Third Parties (including in respect of the Indebtedness of the Company Group or under any Contract), (iii) complying with applicable Law or Order, or (iv) funding any Emergency Expenditures (any such determination by the Board an "Additional Funding Requirement"), then the Board may direct the Company to submit to the Members a written capital funding request notice (a "Capital Request Notice"), which Capital Request Notice shall set forth (A) the anticipated amount of, and the reason for, such Additional Funding Requirement, (B) each Member's requested share of such Additional Funding Requirement, which with respect to each Member shall equal such Member's Percentage Interest multiplied by the aggregate amount of the Additional Funding Requirement (such share, the "Pro Rata Request Amount") and (C) the funding date for such Additional Funding Requirement (the "Capital Request Funding Date"), which Capital Request Funding Date shall not be earlier than twenty (20) days following the date on which such Capital Request Notice is delivered to the Members except for any Capital Request Notices pertaining to Emergency Expenditures in which case the Capital Request Funding Date shall not be earlier than twelve (12) days, provided, that such Capital Request Notices shall not occur more frequently than monthly (except for any Capital Request Notice pertaining to an Emergency Expenditure); provided, further, that, any Capital Request Notice shall only be made to the extent the Board reasonably determines the additional equity capital requested will be timely spent following its contribution by the Members. Any Additional Funding Requirements for the period from the Effective Date and including the date that is seven (7) years from the Effective Date and which do not exceed the Maximum Investor Commitment shall be a "Mandatory Capital Contribution". Any Additional Funding Requirement shall require each Member to contribute its Pro Rata Request Amount; provided, that any obligations of the Investor Members under this Section 5.1(a) to contribute their respective Pro Rata Request Amounts shall be joint and several. Requests for additional equity capital other than pursuant to a Mandatory Capital Contribution shall be determined by the Board and each Member may, but shall not be obligated to, contribute its Pro Rata Request Amount as called for in the applicable Capital Request Notices; provided, that in the event the BIP Investor Member elects to contribute its Pro Rata Request Amount as called for

in the applicable Capital Request Notice and the VCOC Investor Member elects not to contribute its Pro Rata Request Amount, then the BIP Investor Member shall be required to fund the total Pro Rata Request Amount for the Investor Members, including such Pro Rata Request Amount allocated to the VCOC Investor Member. For the avoidance of doubt, other than (i) a Mandatory Capital Contribution pursuant to this Section 5.1, (ii) the joint and several obligations of the Investor Members to contribute their respective Pro Rata Request Amounts as set forth in this Section 5.1 and (iii) any obligation of the BIP Investor Member to fund on any Pro Rata Request Amount allocated to the VCOC Investor Member pursuant to the immediately preceding sentence, no Member shall have any obligation to fund any such requests for additional equity capital unless such Member indicates it will do so in accordance with this Section 5.1. Upon the receipt of a Capital Request Notice, each Member shall, within twelve (12) days of such receipt, provide written notice to the Company and the other Members as to the extent to which such Member intends to fund its Pro Rata Request Amount, whether in whole, in part or not at all (a “Response To Capital Call”). If one Member indicates in its Response To Capital Call that it does not intend to fund its Pro Rata Request Amount in full, and any other Member had, prior thereto, submitted a Response To Capital Call indicating that it intends to fund a greater percentage than any such other Member of its Pro Rata Request Amount, then any such other Member will be entitled to amend its Response To Capital Call to reduce its percentage funding to an amount representing a percentage of its Pro Rata Request Amount not less than the lower percentage indicated in the other Member’s Response to Capital Call; provided, that no Investor Member shall be entitled to reduce its percentage funding pursuant to this sentence if the Member that indicated its intent not to fund its Pro Rata Request Amount in full is an Investor Member. If no Response to Capital Call is received within such twelve (12) days, the Member shall be deemed to have elected to not fund.

(b) If any Member refuses or fails to make all or any portion of its Pro Rata Request Amount pursuant to this Section 5.1 on or prior to the applicable Capital Request Funding Date (such Member, the “Non-Contributing Member”, and the unfunded amount, the “Unfunded Amount”), then the Company shall provide written notice thereof to the other Member(s) (the “Contribution Unfunded Amount Notice”); provided, that if the Non-Contributing Member is an Investor Member, the Investor Members jointly shall be deemed the Non-Contributing Member and all references in this Section 5.1(b) to the Pro Rata Request Amount of the Non-Contributing Member shall refer to the aggregate Pro Rata Request Amount of both Investor Members combined; and

(i) Excess Contribution. To the extent that the Non-Contributing Member contributes less than all of its Pro Rata Request Amount, and any other Member who is not a Non-Contributing Member (an “Over-Contributing Member”) has contributed a greater percentage of its Pro Rata Request Amount than the Non-Contributing Member, such Over-Contributing Member shall have the right to elect to (A) receive a special distribution of the amount of such excess (the “Excess Contribution”), such that the Excess Contribution is returned to such Over-Contributing Member (and the Company shall cause such special distribution to be made as promptly as practicable), (B) have such Excess Contribution be treated as a loan to the Company (consistent with the methodology in clause (ii)(A), below), (C) except in the event that the Non-Contributing Member is the NiSource Member, (1) have such Excess Contribution be treated as a contribution to capital of the Company (consistent with the methodology in clause (ii)(B), below) or (2) so long as the Non-Contributing Member is an Affiliated Member and solely if the Non-Contributing Member has an amount still outstanding under its Equity Commitment Letter under this Agreement, and only up to such amount, have such Excess Contribution be treated as a contribution to capital of NHII on behalf of a NHII Member designated by such Over-Contributing Member (consistent with the methodology in Section 5.1(b)(ii)(B) of the NHII Operating Agreement), which election shall be made by written notice to the Company and the other Members no later than ten (10) Business Days following the date of the Contribution Unfunded Amount Notice and may consist of any combination thereof. Further the Members hereby agree and acknowledge that any Excess Contribution (as defined in the NHII Operating Agreement) under the NHII Operating Agreement, which an Over-Contributing Member (as defined in the NHII Operating Agreement) under the NHII Operating Agreement has elected to be treated as a contribution to capital of the Company (i.e. Generation Holdings II LLC) pursuant to clause (C)(2) of Section 5.1(b)(i) of the NHII Operating Agreement, shall be deemed to be a capital contribution under this Agreement in respect of an Excess Contribution, in accordance with Section 5.1(b)(ii)(B), on behalf of the Member designated by such NHII Member.

(ii) Top-Up Right. A Member that has paid its full Pro Rata Request Amount (the “Contributing Member”; provided, that no Investor Member may be a Contributing Member if the other Investor Member has not paid its full Pro Rata Request Amount unless an Investor Member has funded the full Pro Rata Request Amount of any other Investor Member on behalf of such Investor Member) shall have the right (but not the obligation) to elect to contribute any portion of the Unfunded Amount in accordance with this Section 5.1(b) (X) as a loan to the Company or (Y) except in the event that the Non-Contributing Member is the NiSource Member, (1) as a capital contribution to the Company in accordance with the following procedures or (2) so long the Non-Contributing Member is an Affiliated Member and solely if the Non-Contributing Member has an amount still outstanding under its Equity Commitment Letter under this Agreement, and only up to such amount, as a capital contribution to NHII, in accordance with the procedures set forth below or in Section 5.1(b)(ii)(B) of the NHII Operating Agreement, as applicable, which election shall be made by written notice to the Company and the other Members no later than ten (10) Business Days following the date of the Contribution Unfunded Amount Notice and may consist of any combination thereof. Further the Members hereby agree and acknowledge that any Unfunded Amount (as defined in the NHII Operating Agreement) under the NHII Operating Agreement, which a Contributing Member (as defined in the NHII Operating Agreement) under the NHII Operating Agreement has contributed and elected to be treated as a contribution to capital to the Company (i.e. Generation Holdings II LLC) pursuant to clause (Y)(2) of Section 5.1(b)(ii) of the NHII Operating Agreement, shall be deemed to be a capital contribution in respect of an Unfunded Amount, in accordance with Section 5.1(b)(ii)(B), on behalf of the Member designated by such NHII Member.

(A) Loan. The Contributing Member may elect to advance all or a portion of the Unfunded Amount to the Company on behalf of the Non-Contributing Member, which advance shall be treated as a loan by the Contributing Member to the Company (an “Unfunded Amount Loan”) at an interest rate equal to a floating rate equal to the Wall Street Journal Prime Rate plus 0.75% per annum. Subject to the terms of this Agreement, each Unfunded Amount Loan shall be repaid out of any subsequent distributions made pursuant to Section 5.2 to which the Non-Contributing Member would otherwise be entitled under this Agreement, and such payments shall be applied first to the payment of accrued but unpaid interest on each such Unfunded Amount Loan and then to the payment of the outstanding principal, until such Unfunded Amount Loan is paid in full.

(B) Capital Contribution. Except in the event that the Non-Contributing Member is the NiSource Member, the Contributing Member may elect to contribute an amount equal to all or a portion of the Unfunded Amount to the Company. If the Contributing Member elects to contribute to the Company all or a portion of the Unfunded Amount, then, on or after the earlier of the date that the Non-Contributing Member indicates it will not cure the failure to fund its full Pro Rata Request Amount and the thirtieth (30th) day following the date of the Contribution Unfunded Amount Notice, the Company shall issue to the Contributing Member the amount of additional Membership Interests that can be purchased for such funded amount at a price per Membership Interest equal to ninety percent (90%) of the Fair Market Value of the Company (measured as of the date that such contribution is to be made) per Membership Interest until the NiSource Member has purchased up to \$1,325,000,000.00 of additional Membership Interests pursuant hereto in respect of any Unfunded Amount, and thereafter at Fair Market Value of the Company, and the Contributing Member’s and the Non-Contributing Member’s respective Percentage Interests will be adjusted accordingly. For the avoidance of doubt, this subsection shall in all respects not be subject to the rights and procedures set forth in Section 7.1.

(C) Cure Right. Notwithstanding anything to the contrary in this Section 5.1, on or before the thirtieth (30th) day following the date of the Contribution Unfunded Amount Notice, a Non-Contributing Member may make a contribution to the Company equal to the sum of the Unfunded Amount plus, if the Contributing Member already made an Unfunded Amount Loan in respect of such Unfunded Amount, any interest accrued on the Unfunded Amount Loan, following which (1) the Unfunded Amount advanced by the Contributing Member to the Company together with any such interest shall be paid to the Contributing Member, and (2) the former Non-Contributing Member shall be deemed to have cured its failure to pay the Pro Rata Request Amount prior to the Capital Request Funding Date with respect to the applicable Capital Request Notice.

For the avoidance of doubt, the remedies set forth in Section 5.1(b)(ii)(B) shall not apply to an Event of Default by the NiSource Member.

(c) If the Non-Contributing Member is an Investor Member and it refuses or fails to make its full Pro Rata Request Amount pursuant to this Section 5.1 on or prior to the applicable Capital Request Funding Date and the Contributing Member has not fully funded the Unfunded Amount in accordance with Section 5.1(b), then on or after the thirtieth (30th) day following the date of the applicable Contribution Unfunded Amount Notice, the Board may authorize the Company to seek additional equity funds on commercially reasonable terms from a Third Party in an amount up to the difference between the total Additional Funding Requirement requested and the total funds received by the Company from the Non-Contributing Member and the Contributing Member (including any additional funds that the Contributing Member may have contributed pursuant to Section 5.1(b)), and to issue Membership Interests to Third Parties in connection therewith pursuant to this Section 5.1(c). The terms and rights of the Membership Interests issued pursuant to this Section 5.1 must be on terms no better than the Membership Interests that would have been issued to the applicable Member had they been a Contributing Member. If the Board determines to seek additional equity funds from and issue Membership Interests to a Third Party pursuant to this Section 5.1(c), then the Company must consummate such issuance within 180 days following the Capital Request Funding Date. If such issuance is not consummated within such 180-day period, then the Company's right to so issue Membership Interests to a Third Party in connection with the applicable Additional Funding Requirement shall be lapsed, and the Company shall not thereafter issue any Membership Interests to a Third Party in connection with such Additional Funding Requirement; provided, that, if a definitive agreement providing for such issuance is executed prior to the expiration of such 180-day period but the issuance has not been consummated at the expiration of such period solely as a result of a failure to receive the requisite authorization, approval or consent of any Governmental Body in respect of such issuance, then such period shall be extended solely to the extent necessary to permit the receipt of all such authorizations, approvals or consents which are in process but have not been received from the relevant Governmental Body as of such original expiration date and the consummation of the issuance provided for in such definitive agreement; provided, further, that the Company shall have used its reasonable best efforts in seeking such authorizations, approvals and consents. Upon the completion of such issuance of Membership Interests pursuant to this Section 5.1(c), the Company shall give written notice to the Members of such issuance, which notice shall specify (i) the total number of new Membership Interests issued, (ii) the price per Membership Interest at which the Company issued the Membership Interests, and (iii) any other material terms of the issuance. Upon the issuance of new Membership Interests pursuant to this Section 5.1(c), the Contributing Member's and Non-Contributing Member's respective Percentage Interest will be adjusted accordingly. In no event shall any such issuance be subject to Section 7.1 or 8.1.

(d) If a Member does not make a Mandatory Capital Contribution or indicates in its Response to Capital Call that it shall make its Pro Rata Request Amount but then does not fund such amounts, such Member shall be a Defaulting Member, provided, that at any time the Defaulting Member is an Investor Member, then both Investor Members shall be deemed Defaulting Members until such Investor Member ceases to be a Defaulting Member according to the terms of this Agreement.

(e) In the event that there is an Investor Call Trigger, the NiSource Member (or its Affiliate) may (but is not required to), at its option at any time, acquire all (but not less than all) of the Membership Interests held by the Investor Members (the "Call Right") by giving written notice (the "Call Notice") to the BIP Investor Member of its election to exercise the Call Right; provided, that, other than with respect to clause (ii) or (iii) of the definition of Investor Call Trigger, the applicable Investor Member shall have sixty (60) days following the Call Notice to cure the event giving rise to the Call Notice, if capable of being so cured (the "Cure Period"). The purchase price payable by the NiSource Member in connection with the exercise of the Call Right shall be equal to the product of (i) with respect to an Investor Call Trigger pursuant to clause (i) of the definition thereof, ninety percent (90%) of the Fair Market Value of the Company; (ii) with respect to an Investor Call Trigger pursuant to clause (ii) of the definition thereof, one hundred percent (100%) of the Fair Market Value of the Company; and (iii) with respect to an Investor Call Trigger pursuant to clause (iii) of the definition thereof, the greater of one hundred percent (100%) of the Fair Market Value of the Company or such amount which would satisfy the Spin Return Threshold (in each case, measured as of the date of the delivery of the Call Notice to the BIP Investor Member), multiplied (ii) by a fraction, (A) the numerator of which is the number of Membership Interests

that the Investor Members own in the aggregate at such time and (B) the denominator of which is the total number of Membership Interests then outstanding (the amount equal to such product, the “Call Exercise Price”). If the Call Right is exercised by the NiSource Member, each of the Parties shall take all actions as may be reasonably necessary to consummate the transactions contemplated by this Section 5.1(e) as promptly as practicable, but in any event not later than thirty (30) days after the end of the Cure Period, or so long as necessary to obtain all required authorizations, approvals, or consents (such period, the “Call Consummation Period”), including entering into agreements and delivering certificates and instruments and consents as may be deemed necessary; provided, that, with respect to an Investor Call Trigger pursuant to clause (iii) of the definition thereof, the closing of the Call Right shall occur concurrently with or immediately prior to the underlying spin-off, split-off or similar transaction giving rise to the Call Right. If either Investor Member fails to take all actions necessary to consummate the Transfer of the Membership Interests held by it in accordance with this Section 5.1(e) prior to the expiration of the Call Consummation Period, then the Investor Members jointly shall be deemed to be in material breach of this Agreement for purposes of Article IV and for all other purposes hereunder, shall be deemed a Defaulting Member, and shall be deemed to have granted (and hereby grants, contingent only on the occurrence of such failure) an irrevocable appointment of any Person nominated for the purpose by the NiSource Member to be the Investor Members’ agent and attorney to execute all necessary documentation and instruments on its behalf to Transfer the Investor Member’s Membership Interests to the Company as the holder thereof, in each case consistent with the provisions of this Section 5.1(e). At the consummation of any purchase and sale pursuant to this Section 5.1(e), the Investor Members shall sell to the NiSource Member all of the Membership Interests owned by the Investor Members in exchange for the Call Exercise Price. Contemporaneously with its receipt from the NiSource Member of the Call Exercise Price, the Investor Members shall Transfer to the NiSource Member all of the Membership Interests owned by the Investor Members, free and clear of all Liens. The Members and the Company acknowledge and agree that they shall cooperate reasonably to obtain any necessary authorization, approval or consent of any Governmental Body to consummate the transactions contemplated by this Section 5.1(e). For the avoidance of doubt, in the event the Call Right is exercised, the BIP Investor Member may request the Fair Market Value be determined in accordance with Section 13.15, regardless of the Investor Members’ aggregate Percentage Interest at such time.

(f) The BIP Investor Member has delivered to the Company on the Effective Date the Equity Commitment Letter. In the event that either Investor Member fails to make any Mandatory Capital Contribution from the Effective Date to and including the seventh (7th) anniversary of the Effective Date, and so long as the Maximum Investor Commitment has not been fully paid, the Company shall be entitled to enforce the Equity Commitment Letter for any portion of the Investor Members’ aggregate Pro Rata Request Amount, in addition to the other remedies provided herein (with the Directors appointed by the BIP Investor Member abstaining from determining any such enforcement).

Section 5.2 Distributions Generally.

(a) Except as otherwise provided herein and subject to Section 5.2(b), Section 5.2(c), and the Act, no later than seventy-five (75) days after the end of each fiscal quarter, the Company shall make distributions of the amount of Available Cash. The Company may make such other more frequent distributions (including interim distributions) at such times and in such amounts as the Board may determine.

(b) Except as otherwise provided herein (including the fourth Recital of this Agreement), all distributions shall be paid to the Members only in cash and in the same proportion as their respective Percentage Interest; provided, that, in the case of distributions to be paid in respect of any period during which the Percentage Interest of the Members changed, such distributions shall be prorated to reflect the Percentage Interest of the Members on each day of such measurement period, and the Company and the Members shall take such action as necessary to effectuate such proration.

(c) With respect to each taxable year, at such times necessary to allow the Members to timely satisfy all of their U.S. federal, state and local and non-U.S. tax liabilities, prior to any distributions pursuant to Section 5.2(a) and subject to Available Cash and any restrictions contained in any loan agreement or other contract to which the Company is a party or by which it is bound, the Company shall make cash distributions (“Tax Distributions”) to each Member equal to such Member’s quarterly Assumed Tax Liability determined based on the Board’s good faith estimate of the projected Profits for

such taxable year; provided, however, that to the extent a Member would otherwise be entitled to receive less than its Percentage Interest of the aggregate Tax Distributions to be paid pursuant to this Section 5.2(c) on any given date, then the Tax Distributions to such Member shall be increased, as necessary, to ensure that all such Tax Distributions made pursuant to this Section 5.2(c) are made pro rata in accordance with the Members' respective Percentage Interests. The Company and the Board shall not have any liability to any Member for penalties arising from non-payment or incorrect estimates of such Member's estimated tax payments. Any distributions made pursuant to this Section 5.2(c) shall be treated for purposes of this Agreement as having been distributed pursuant to Section 5.2(a) and shall reduce, dollar-for-dollar, the amount otherwise distributable to such Member pursuant to Section 5.2(a). To the extent the Company does not have sufficient funds and thereby is unable to pay to the Members the full amount of any Tax Distribution otherwise payable pursuant to this Section 5.2(c), the Company shall pay the amount of such shortfall to the Members (pro rata, in accordance with the amount of any such shortfall then owing to such Members) as promptly thereafter as such funds become available. If with respect to any taxable year, the aggregate amount of distributions made to a Member under this Section 5.2(c) is in excess of the amount that would result from the application of this Section 5.2(c) to the entire taxable year, then the amount of such excess shall be treated as an advance against, and shall reduce the amount of, any future distributions made with respect to such Member pursuant to this Section 5.2(c), but shall not reduce Tax Distributions made to a Member to provide such Member with its pro rata Percentage Interest of Tax Distributions.

(d) Notwithstanding the terms of this Section 5.2 and any other provision of this Agreement, (i) the Company shall not make any distribution to any Member on account of its Membership Interests to the extent such distribution would violate the Act, other applicable Law or an Order, and (ii) a Member may direct the payment of part or all of any distribution to another Person by providing written notice of such direction to the Company.

Section 5.3 Distributions upon the Occurrence of an Event of Dissolution. Upon the occurrence of an Event of Dissolution, the Board will proceed, subject to the provisions herein, to wind up the affairs of the Company, liquidate and distribute the remaining assets of the Company (provided, however, that all distributions shall be paid to the Members only in cash and in accordance with their Percentage Interests) and apply the proceeds of such liquidation in the order of priority in accordance with Section 18-804 of the Act or as may otherwise be agreed to by the Members. If the assets of the Company remaining after the payment or discharge of all debts and liabilities of the Company are insufficient to return capital contributions of each Member, such Member shall have no recourse against the Company or any other Member.

Section 5.4 Capital Accounts.

(a) A separate Capital Account for each Member shall be established on the books and records of the Company in compliance with Section 704(b) of the Code and the Treasury Regulations. The initial Capital Accounts, immediately following the contribution and distribution of the Initial Investor Contribution, of each Member are set forth on Schedule 1. This Section 5.4(a) and the other provisions of this Agreement relating to the maintenance of Capital Accounts are intended to comply with Treasury Regulation Sections 1.704-1(b) and 1.704-2, and shall be interpreted and applied in a manner consistent with such Treasury Regulation, as determined by the Board in its reasonable discretion.

(b) No Member shall be required to pay to any other Member or the Company any deficit or negative balance which may exist from time to time in such Member's Capital Account (including upon and after dissolution of the Company).

Section 5.5 Withdrawal of Capital; Interest. Except as expressly provided in this Agreement, (a) no Member may withdraw capital or receive any distributions from the Company and (b) no interest shall be paid by the Company on any capital contribution or distribution.

Section 5.6 Allocation of Profits and Losses.

(a) Subject to Section 5.6(b), and after the application of the allocation rules in Section 5.7, Profits and Losses and, if the Board in its discretion determines it to be necessary, individual items thereof, for an Allocation Year (or other relevant period) shall be allocated among the Members for such Allocation Year (or other relevant period) in a manner determined by the Board so as to produce, as nearly as possible, the sum of (a) the Capital Account balance for each Member at the end of such Allocation Year (or other relevant period) and (b) such Member's share of Company Minimum Gain and

Member Nonrecourse Debt Minimum Gain, if any, equal to the hypothetical cash that would be distributed to such Member if (x) the Company were dissolved, its affairs wound up and its assets sold for an amount of hypothetical cash equal to the sum of the Gross Asset Values of the assets at the end of such Allocation Year (or other relevant period), (y) the Company paid all of its liabilities in accordance with their terms up to the amount of the hypothetical cash (limited with respect to each Nonrecourse Liability to the Gross Asset Value of the asset securing such liability), and (z) the remaining hypothetical cash from the deemed sale were immediately distributed to the Members in accordance with Section 5.3.

(b) Notwithstanding the foregoing provisions of Section 5.6(a), the Losses (or items of expense or deduction or loss) allocated pursuant to Section 5.6(a) shall not exceed the maximum amount that can be so allocated without causing any Member to have an Adjusted Capital Account Deficit at the end of any Allocation Year (or other relevant period). In the event some, but not all, of the Members would have an Adjusted Capital Account Deficit as a consequence of an allocation of Losses pursuant to Section 5.6(a), the limitation set forth in this Section 5.6(b) shall be applied on a Member-by-Member basis so as to allocate the maximum permissible Losses to each Member under Treasury Regulations Section 1.704-1(b)(2)(ii)(d). All Losses (or items of expense or deduction or loss) in excess of the limitation set forth in this Section 5.6(b) shall be allocated to other Members in accordance with the positive balances in such Members' Adjusted Capital Accounts so as to allocate the maximum permissible Losses to each Member under Treasury Regulations Section 1.704-1(b)(2)(ii)(d).

Section 5.7 Special Allocations. Any allocation of Profits and Losses (or items thereof) for purposes of maintaining Capital Accounts will, however, be subject to any adjustment required to comply with Treasury Regulations Sections 1.704-1 and 1.704-2, including the following adjustments and special allocations which shall be made in the following order of priority and prior to any allocation under Section 5.6(a):

(a) Except as otherwise provided in Treasury Regulations Section 1.704-2(f), notwithstanding any other provision of this Article V, if there is a net decrease in Company Minimum Gain during an Allocation Year (or other relevant period), then each Member shall be specially allocated items of Company income and gain for such Allocation Year (or other relevant period) (and, if necessary, for subsequent Allocation Years (or other relevant periods)) in an amount equal to such Member's share of the net decrease in Company Minimum Gain, determined in accordance with Treasury Regulations Section 1.704-2(g)(2). Allocations pursuant to the previous sentence shall be made in proportion to the respective amounts required to be allocated to each Member in accordance with Treasury Regulations Sections 1.704-2(f)(6) and 1.704-2(j)(2). This Section 5.7(a) is intended to comply with the minimum gain chargeback requirement of Treasury Regulations Section 1.704-2(f) and shall be interpreted consistently therewith.

(b) Except as otherwise provided in Treasury Regulations Section 1.704-2(i)(4), notwithstanding any other provision of this Article V, if there is a net decrease in Member Nonrecourse Debt Minimum Gain attributable to a Member Nonrecourse Debt during any Allocation Year (or other relevant period), then each Member who has a share of the Member Nonrecourse Debt Minimum Gain attributable to such Member Nonrecourse Debt, determined in accordance with Treasury Regulations Section 1.704-2(i)(5), shall be specially allocated items of Company income and gain for such Allocation Year (or other relevant period) (and, if necessary, for subsequent Allocation Years (or other relevant periods)) in an amount equal to such Member's share of the net decrease in Member Nonrecourse Debt Minimum Gain attributable to such Member Nonrecourse Debt, determined in a manner consistent with the provisions of Treasury Regulations Section 1.704-2(i)(4). The items to be allocated shall be determined in accordance with Treasury Regulations Sections 1.704-2(i)(4) and 1.704-2(j)(2). This Section 5.7(b) is intended to comply with the Member nonrecourse debt minimum gain chargeback requirement of Regulations Section 1.704-2(i)(4) and shall be interpreted consistently therewith.

(c) If any Member unexpectedly receives an adjustment, allocation, or distribution of the type contemplated by Treasury Regulations Sections 1.704-1(b)(2)(ii)(d)(4), 1.704-1(b)(2)(ii)(d)(5) or 1.704-1(b)(2)(ii)(d)(6) resulting in, or increasing, an Adjusted Capital Account Deficit for such Member, then items of Company income and gain shall be specially allocated to all such Members in an amount and manner sufficient to eliminate, to the extent required by the Treasury Regulations, the Adjusted Capital Account Deficit of such Member as quickly as possible, provided that an allocation pursuant to this Section 5.7(c) shall be made only if and to the extent that such Member would have an Adjusted

Capital Account Deficit after all other allocations provided for in this Article V have been tentatively made as if this Section 5.7(c) were not in this Agreement. It is intended that this Section 5.7(c) qualify and be construed as a “qualified income offset” within the meaning of Treasury Regulations Section 1.704-1(b)(2)(ii)(d) and shall be interpreted consistently therewith.

(d) If any Member has an Adjusted Capital Account Deficit at the end of any Allocation Year (or other relevant period) in excess of the sum of (A) the amount such Member is required to restore pursuant to the provisions of this Agreement and (B) the amount such Member is deemed obligated to restore pursuant to Treasury Regulations Sections 1.704-2(g) and 1.704-2(i)(5), such Member shall be specially allocated items of Company income and gain in the amount of such deficit as quickly as possible; provided, however, that an allocation pursuant to this Section 5.7(d) shall be made only if and to the extent that such Member would have an Adjusted Capital Account Deficit after all other allocations provided for in this Section 5.7 have been tentatively made as if Section 5.7(c) and this Section 5.7(d) were not in this Agreement.

(e) To the extent that an adjustment to the adjusted tax basis of any Company asset pursuant to Code Section 734(b) is required, pursuant to Treasury Regulations Section 1.704-1(b)(2)(iv)(m), to be taken into account in determining Capital Accounts as the result of a distribution to a Member in complete liquidation of its Membership Interest, the amount of such adjustment to the Capital Accounts shall be treated as an item of gain (if the adjustment increases the basis of the asset) or loss (if the adjustment decreases such basis), and such gain or loss shall be specially allocated to the Members in a manner consistent with the manner in which their Capital Accounts are required to be adjusted pursuant to Treasury Regulations Section 1.704-1(b)(2)(iv)(m).

(f) The Nonrecourse Deductions for each Allocation Year (or other relevant period) shall be allocated to the Members in proportion to their relative Percentage Interests.

(g) The Member Nonrecourse Deductions shall be allocated each Allocation Year (or other relevant period) to the Member that bears the economic risk of loss (within the meaning of Treasury Regulations Section 1.752-2) for the Member Nonrecourse Debt to which such Member Nonrecourse Deductions are attributable.

(h) The allocations set forth in Section 5.7(a) through Section 5.7(g) (collectively, the “Regulatory Allocations”) are intended to comply with certain requirements of the Treasury Regulations. It is the intent of the parties to this Agreement that, to the extent possible, all Regulatory Allocations will be offset in the current Allocation Year or future Allocation Years either with other Regulatory Allocations or with special allocations of other items of Company income, gain, loss or deduction pursuant to this Article V. Therefore, notwithstanding any other provision of this Section 5.7(h) (other than the Regulatory Allocations), the Board shall make such offsetting special allocations of Company income, gain, loss, or deduction (to the extent permissible) among the Members so that, after such offsetting allocations are made, each Member’s Capital Account balance is, to the extent possible, equal to the Capital Account balance such Member would have had if the Regulatory Allocations were not part of the Agreement and all Company items were allocated pursuant to Section 5.6(a).

Section 5.8 Other Allocation Rules for Profits and Losses for Capital Accounts.

(a) In the event Members are admitted to the Company pursuant to this Agreement on different dates, the Company items of income, gain, loss, deduction, and credit allocated to the Members for each Allocation Year during which Members are so admitted shall be allocated among the Members in proportion to their respective interests during such Allocation Year using any reasonable convention permitted by Section 706 of the Code and selected by the Board (or its designee).

(b) In the event a Member transfers its Membership Interests during an Allocation Year, the allocation of Company items of income, gain, loss, deduction, and credit allocated to such Member and its transferee for such Allocation Year shall be made between such Member and its transferee in accordance with Section 706 of the Code using any reasonable convention permitted by Section 706 of the Code and selected by the Board (or its designee).

Section 5.9 Tax Allocations; Code Section 704(c) Allocations.

(a) Except as provided in this Section 5.9, for income tax purposes under the Code and the Treasury Regulations each Company item of income, gain, loss, deduction and credit shall be allocated among the Members in the same manner as its correlative item of Profit and Loss for the Allocation Year (or other relevant period).

(b) In accordance with Code Section 704(c) and the Treasury Regulations, items of income, gain, loss, and deduction with respect to any property of the Company shall, solely for income tax purposes, be allocated among the Members so as to take account of any variation between the adjusted tax basis of such property and its initial Gross Asset Value pursuant to any permissible method under the Treasury Regulations as may be determined by the Partnership Representative in its discretion; provided, however, with respect to any Company asset that is contributed to the Company with a Gross Asset Value that varies from its basis in the hands of the contributing Member immediately preceding the date of contribution shall be allocated among the Members for income tax purposes using the “traditional method,” with no “curative allocation” of income or gain to offset any “shortfall” in depreciation that results by reason of the use of the “traditional method,” as defined in Treasury Regulations Section 1.704-3(b), including upon sale of any property or upon the a subsequent issuance of additional membership interests, an in-kind contribution of property to the Company in exchange for membership interest, or a redemption of membership interests.

(c) If any portion of gain recognized from the disposition of assets by the Company represents the “recapture” of previously allocated deductions by virtue of the application of Code Section 1245 or 1250 (the “Recapture Gain”), such Recapture Gain shall be allocated, solely for income tax purposes, in accordance with Treasury Regulations Sections 1.1245-1(e)(2) and (3) and 1.1250-1(f).

(d) Tax credits and tax credit recapture shall be allocated among the Members in accordance with any reasonable method selected by the Board (or its designee) that is permitted by applicable tax laws.

(e) Unless otherwise provided in this Section 5.9, any material elections or other decisions relating to allocations for income tax purposes, including selecting any allocation method under Treasury Regulation Section 1.704-3, shall be made by the Board and shall reflect the economic intent of parties.

(f) Allocations pursuant to this Section 5.9 are solely for income tax purposes and shall not affect, or in any way be taken into account in computing, any Member’s Capital Account.

Section 5.10 Allocation of Liabilities. The liabilities of the Company shall be allocated to the Members in any manner permitted under Code Section 752 and Treasury Regulations promulgated thereunder and as selected by the Board (or its designee).

Section 5.11 Compliance with Tax Laws. The allocation rules set forth in Section 5.6 through Section 5.10 are intended to comply with the Code and Treasury Regulations and to ensure that all allocations under this Article V are respected for United States federal income tax purposes and shall be interpreted consistently with such intent. If, for any reason, the Board determines that any provision of Section 5.6 through Section 5.10 does not comply with the Code or Treasury Regulations or that the allocations under this Article V may not be respected for United States federal income tax purposes, the Board may, subject to the next sentence, take all reasonable actions, including amending this Article V or adjusting a Member’s Capital Account or how Capital Accounts are maintained, to ensure compliance with the Code and Treasury Regulations and that the allocations provided for in this Article V shall be respected for United States federal income tax purposes. Nothing in this Section 5.11 shall permit any changes to the provisions of Section 5.2 or Section 5.3.

Article VI **TRANSFERS OF MEMBERSHIP INTERESTS**

Section 6.1 General Restriction.

(a) No Member shall Transfer any of its Membership Interests except pursuant to and in accordance with this Article VI. Any purported Transfer by any Member of its Membership Interests in violation of this Section 6.1(a), or without compliance in all respects with the provisions of this Article VI pertaining to such purported Transfer, shall be invalid and void ab initio, and such purported Transfer by such Member shall constitute a material breach of this Agreement for purposes of Article VI.

(b) Subject to Section 6.2, neither Investor Member may Transfer any of its Membership Interests to any Person prior to the date that is the seventh (7th) anniversary of the Effective Date (the “Lock-Up Period”) other than with the prior written consent of the NiSource Member. After the expiration of the Lock-Up Period, each Investor Member, as applicable, may Transfer its Membership Interests in accordance with this Article VI. Notwithstanding the forgoing, each Investor Member may at any time Transfer Membership Interests in compliance with Section 6.2.

(c) Transfers by Members in accordance with and pursuant to this Article VI shall entitle each applicable transferee to the rights and obligations of the transferor under this Agreement.

(d) The Investor Members and the NiSource Member acknowledge any indirect Transfers of any Member’s Membership Interest shall be deemed a Transfer by such Member hereunder.

(e) The Parent has joined this Agreement solely for the purpose of acknowledging the obligations of the NiSource Member under this Article VI.

Section 6.2 Transfers to Permitted Transferees; Liens by Members.

(a) Notwithstanding Section 6.1, each Member may Transfer at any time all or any portion of the Membership Interests held by it to any one of its Permitted Transferees; provided, that, in connection with any such Transfer, (a) such Permitted Transferee shall, in writing, assume all of the rights and obligations of the transferring Member as a Member under this Agreement and as a Party hereto with respect to the Transferred Membership Interests, (b) such Permitted Transferee is as creditworthy as the transferring Member and provides evidence thereof to the non-transferring Members, (c) the transferring Member remains liable for all liabilities and obligations of the Permitted Transferee, and (d) effective provision shall be made whereby such Permitted Transferee shall be required, prior to the time when it shall cease to be a Permitted Transferee of the transferring Member, to Transfer such Membership Interests to the transferring Member or to another Person that would be a Permitted Transferee of the transferring Member as of such applicable time. In the event that a Member (including, as the case may be, a Permitted Transferee) intends to Transfer its Membership Interests to a Permitted Transferee, such transferring Member or the Permitted Transferee, as applicable, shall notify the other Members and the Company of the intended Transfer at least twenty (20) Business Days prior to the intended Transfer.

(b) Each Member shall be permitted to directly or indirectly Encumber its Membership Interests or any Equity Interests in such Member in connection with any debt financing, the proceeds of which have been or will be used by such Member to finance its purchase of such Membership Interests (whether in respect of an issuance of new Membership Interests by the Company or the purchase of existing Membership Interests from a Member or the refinancing of any such debt financing in the future), to fund the capital expenditure needs of the Company and its Subsidiaries or to fund its capital needs for any Mandatory Capital Contribution and neither such Lien nor any commencement or consummation of foreclosure proceedings or exercise of foreclosure remedies by a secured party on a Member’s Membership Interests Encumbered in connection with any such debt financing shall, in either case, be considered a “Transfer” for any purpose under this Agreement; provided, that (i) such Member shall be obligated to promptly notify the other Members and the Company in writing following the commencement of any such foreclosure remedies or proceedings, (ii) in the event of the consummation of such a foreclosure, such Member will automatically cease to be deemed the owner of the Membership Interests so foreclosed and will cease to have any rights in respect thereof (with the financing source foreclosing on such Membership Interests succeeding to the rights and responsibilities of the Member hereunder), and (iii) the consummation of any such foreclosure will be subject to the receipt of any required authorization, approval or consent of all applicable Governmental Bodies; provided, further, following exercise of any foreclosure or similar rights, such lender or similar Person may not further Transfer such Membership Interests without complying with this Article VI, including, Section 6.3.

Section 6.3 Right of First Offer.

(a) Prior to any Transfer by a Member (each, a “Transferring Member”) of all or any portion of its Membership Interests other than to a Permitted Transferee of such Transferring Member, the Transferring Member must first offer to sell to the other Members (the “Non-Transferring Member”; provided, that (x) if the Transferring Member is an Investor Member, the other Investor Member shall not be deemed a Non-Transferring Member for any purpose under this Section 6.3 and (y) if the Transferring

Member is the NiSource Member, the Investor Members jointly shall be deemed the Non-Transferring Member for all purposes under this Section 6.3) all of its Membership Interests that it desires to sell (such Membership Interests to be offered for sale to the Non-Transferring Member pursuant to this Section 6.3, the “Subject Membership Interests”), in each case, in accordance with the procedures set forth in the provisions of this Section 6.3.

(i)

(A) If the Investor Member is the Transferring Member, the Investor Member shall first deliver to the Non-Transferring Member a written notice which shall be a binding offer (an “Investor Sale Notice”) setting forth the cash price and all other material terms and conditions at which the Investor Member is willing to sell the Subject Membership Interests to the Non-Transferring Member, which notice shall constitute an offer to the Non-Transferring Member to effect such purchase and sale on the terms set forth therein. Any such Investor Sale Notice shall be firm, not subject to withdrawal, and prepared and delivered in good faith. Within ninety (90) days following its receipt of an Investor Sale Notice, the Non-Transferring Member may accept the Investor Member’s offer and purchase the Subject Membership Interests at the cash price and upon the other material terms and conditions set forth in the Investor Sale Notice, in which event the closing of the purchase and sale of the Subject Membership Interests will take place as promptly as practicable, subject to customary closing conditions, including the receipt of required regulatory approvals.

(B) If the NiSource Member is the Transferring Member, the NiSource Member shall first deliver to the Non-Transferring Member a written right of first offer notice (a “NiSource Sale Notice”) describing the Subject Membership Interests and setting forth all other material terms and conditions (other than the cash price) upon which the NiSource Member is willing to sell the Subject Membership Interests to the Non-Transferring Member. The NiSource Sale Notice shall not be a binding offer and need not include a price. Within ninety (90) days following its receipt of a NiSource Sale Notice, the Investor Member (as the Non-Transferring Member) may deliver to the NiSource Member a written response setting forth the cash price and confirming the other material terms and conditions specified in the NiSource Sale Notice (the “Investor Offer”). The Investor Offer shall be a binding offer by the Investor Member to purchase the Subject Membership Interests on the terms set forth therein, shall be firm, not subject to withdrawal, and prepared and delivered in good faith, and shall remain open for acceptance by the NiSource Member for a period of ninety (90) days following the NiSource Member’s receipt thereof. The NiSource Member may accept the Investor Offer within such ninety (90)-day period, in which event the closing of the purchase and sale of the Subject Membership Interests will take place as promptly as practicable, subject to customary closing conditions, including the receipt of required regulatory approvals. If the NiSource Member does not accept the Investor Offer within such ninety (90)-day period, the Investor Offer shall be deemed rejected and shall terminate without further action by any party.

(ii) If the NiSource Member does not accept the offer made pursuant to the Investor Sale Notice or the Investor Offer within such ninety (90)-day period (or if the Investor Member does not make an Investor Offer within ninety (90) days following receipt of a NiSource Sale Notice), then the Transferring Member will, for a period of one hundred eighty (180) days commencing on the earlier of (A) the expiration of such ninety (90)-day period (or ninety (90) -day period if the Investor Member does not make an Investor Offer) and (B) the delivery of a written notice by the NiSource Member to the Investor Member rejecting the offer set forth in the Investor Sale Notice or Investor Offer, as applicable, (if any) (such one hundred eighty (180)-day period, the “Sale Period”), be entitled to sell the Subject Membership Interests to any one Third Party for (x) in the case of the NiSource Member being the Transferring Member, at any higher price than the price set forth in the Investor Offer (or at any price if the Investor Member does not make an Investor Offer) and (y) in the case of the Investor Member being the Transferring Member, at a price greater than one hundred and seven and a half percent (107.5%) of the price set forth in the Investor Sale Notice (the “Threshold Price”) and upon other terms and conditions (excluding price) that are not more favorable to the acquirer than those specified in the Investor Sale Notice or Investor Offer, as applicable, subject to the other terms of this Section 6.3 (including Section

6.3(e)); provided, that, to the extent the Investor Member receives a price lower than the Threshold Price, the Investor Member will offer to sell such Subject Membership Interests at the offered price to the NiSource Member and the NiSource Member shall have thirty (30) days to accept such offer; provided, if the NiSource Member does not accept such offer or respond in that period, then the Investor Member may sell the Subject Membership Interests to the third party at the revised price that is below the Threshold Price. If such sale to any Third Party is not completed prior to the expiration of the Sale Period, then the process initiated by the delivery of the Investor Sale Notice or NiSource Sale Notice, as applicable, shall be lapsed, and the Transferring Member will be required to repeat the process set forth in this Section 6.3 before entering into any agreement with respect to, or consummating, any sale of Membership Interests to any Third Party; provided, that if a definitive agreement providing for the consummation of such sale is executed within the Sale Period but such sale has not been consummated at the expiration of the Sale Period solely as a result of a failure to receive the requisite authorization, approval or consent of any Governmental Body in respect of such sale, then the Sale Period shall be extended solely to the extent necessary to permit the receipt of all such authorizations, approvals or consents which are in process but have not been received from the relevant Governmental Body as of the original expiration date of the Sale Period and the consummation of the sale provided for in such definitive agreement; provided, that the Transferring Member shall have used efforts in seeking such authorizations, approvals and consents, consistent with its obligations under such definitive agreements in respect thereof.

(b) The Investor Members and their respective Permitted Transferees (if any) shall not be permitted to Transfer any of their Membership Interests to a Prohibited Competitor without the prior written consent of the NiSource Member. Within ten (10) Business Days after January 1 of each year, the NiSource Member shall have the right (i) to update the list of Prohibited Competitors set forth on Appendix (A) to replace no more than three (3) of the Prohibited Competitors with other Competitors designated by the NiSource Member, and (ii) in addition to any replacements pursuant to clause (i), to add up to two (2) additional Competitors designated by the NiSource Member to such list.

(c) No Transfer of Membership Interests by an Investor Member to any Third Party pursuant to Section 6.3(a)(ii) may be effected if it would, or would reasonably be expected to in the reasonable and good faith determination of the NiSource Member in consultation with the Board, (i) have a material and adverse effect on the Company Group or (ii) create a material risk of a material adverse regulatory consequence on any member of the Company Group or the Outside Group as a result of the identity of the Third Party transferee, any action taken or reasonably expected to be taken by any Governmental Body with respect to such Transfer or change in Tax status of any Person caused or reasonably expected to be caused by such Transfer, any terms or conditions of such Transfer, any requirement that the Membership Interests be registered under any applicable securities Laws in connection with or as a result of such Transfer, or any other similar matter. For purposes of this Section 6.3 and Section 6.4, "control" means (x) the ownership of at least a majority of the issued and outstanding Membership Interests of the Company, or (y) the ability to elect, directly or indirectly, a majority of the Directors of the Company in accordance with this Agreement.

(d) Prior to the consummation of any Transfer pursuant to Section 6.3(a)(ii), the Transferring Member shall have delivered to the Board and the Non-Transferring Member evidence reasonably satisfactory to the Board (with the Directors appointed by the Transferring Member abstaining from any such determination) and to the Non-Transferring Member that (i) the transferee is a Qualified Transferee and (ii) the Transfer complies with the provisions of Section 6.3(b) (if applicable) and Section 6.3(c).

(e) Any sale by the Transferring Member to the Non-Transferring Member, pursuant to Section 6.3(a) shall be consummated pursuant to a membership interest purchase agreement which shall contain representations and warranties by the Transferring Member to the Non-Transferring Member that (i) the Transferring Member has full right, title and interest in and to the Subject Membership Interests, (ii) the Transferring Member has all the necessary power and authority and has taken all necessary action to Transfer the Subject Membership Interests to the Non-Transferring Member as contemplated by this Section 6.3, (iii) the Subject Membership Interests are free and clear of any and all Liens other than those arising as a result of or under the terms of this Agreement and those arising under securities Laws of general applicability pertaining to limitations on the transfer of unregistered securities and (iv) other customary representations and warranties.

Section 6.4 Tag-Along Rights.

(a) Other than with respect to a Transfer proposed and made in accordance with Section 6.5, in the event that the NiSource Member proposes to effect a Transfer to a Third Party transferee (the "Tag-Along Buyer") of a number of its Membership Interests constituting more than 25% of the total Membership Interests then outstanding (a "Tag-Along Sale"), then the NiSource Member shall give the Investor Members written notice (a "Tag-Along Notice") of such proposed Transfer at least thirty (30) days prior to the consummation of such Tag-Along Sale, setting forth (w) the number of Membership Interests ("Tag-Along Offered Membership Interests") proposed to be Transferred to the Tag-Along Buyer and the purchase price, (x) the identity of the Tag-Along Buyer, (y) any other material terms and conditions of the proposed Transfer and (z) the intended dates on which the NiSource Member will enter into a definitive agreement in respect of such proposed Transfer and consummate such proposed Transfer.

(b) Upon delivery of a Tag-Along Notice, the Investor Members shall have the right to sell up to their respective Tag Portions, at the same price per Membership Interest, for the same form of consideration and pursuant to the same terms and conditions (including time of payment) as set forth in the Tag-Along Notice (or, if different, as such are applicable at the time of the entry into a definitive agreement in respect of, or at the time of the consummation of, the Tag-Along Sale). If an Investor Member wishes to participate in the Tag-Along Sale, then such Investor Member shall provide written notice to the NiSource Member no less than forty-five (45) days after the date of the Tag-Along Notice, indicating such election, provided however if the BIP Investor Member elects to sell its respective Tag Portion the VCOC Investor Member shall be required to sell its respective Tag Portion on the same terms set forth in the election notice by the BIP Investor Member. Such notice shall set forth the number of its Membership Interests that such Investor Member elects to include in the Tag-Along Sale (which number shall not exceed its Tag Portion), and such notice shall constitute such Investor Member's binding agreement to sell such Membership Interests on the terms and subject to the conditions applicable to the Tag-Along Sale.

(c) Any Transfer of an Investor Member's Membership Interests in a Tag-Along Sale shall be on the same terms and conditions as the Transfer of the NiSource Member's Membership Interests in such Tag-Along Sale, except as otherwise provided in this Section 6.4(c). Any participating Investor Member shall be required to make customary representations and warranties in connection with the Transfer of its Membership Interests, including as to its ownership and authority to Transfer, free and clear of all Liens, such Membership Interests and shall indemnify and hold harmless, to the fullest extent permitted by applicable Law, the Tag-Along Buyer against all losses of whatever nature arising out of, in connection with or related to any breach of any representation or warranty made by, or agreements, understandings or covenants of such Investor Member, as the case may be, under the terms of the agreements relating to such Transfer of such Investor Member's Membership Interests, in each case not to exceed the equivalent obligations to indemnify and hold harmless the Tag-Along Buyer provided by the NiSource Member; provided, that (i) liability for misrepresentation or indemnity shall (as between the NiSource Member and any such Investor Member) be expressly stated to be several but not joint and the NiSource Member and any such Investor Member shall not be liable for any breach of covenants or representations or warranties as to the Membership Interests of any other Member and shall not, in any event, be liable for more than its pro rata share (based on the proceeds to be received) of any liability for misrepresentation or indemnity, (ii) any participating Investor Member shall benefit from any releases of sellers or other provisions in the transaction documentation of general applicability to sellers to the same extent as the NiSource Member, (iii) any participating Investor Member shall not be obligated to agree to any non-customary administrative covenants (such as any non-compete covenants that would restrict its or its Affiliates' business activities), and (iv) any participating Investor Member shall not be obligated to provide indemnification obligations that exceed its proceeds from the Tag-Along Sale.

(d) Notwithstanding the foregoing, and for the avoidance of doubt, no Investor Member shall be entitled to Transfer its Membership Interests pursuant to this Section 6.4 in the event that, notwithstanding delivery of a written notice of election to participate in such Tag-Along Sale pursuant to this Section 6.4, such Investor Member fails to consummate the Transfer of its Membership Interests (on the terms and conditions required by this Section 6.4) in the applicable Tag-Along Sale.

(e) For the avoidance of doubt, the rights conferred to each Investor Member under this Section 6.4 do not apply in the event of a Change in Control of the NiSource Member.

Section 6.5 Drag-Along Rights.

(a) In the event that the NiSource Member intends to effect a sale of all or any portion of the Membership Interests owned by the NiSource Member and such Membership Interests constitute at least a majority of the issued and outstanding Membership Interests of the Company (a "Drag-Along Sale"), then the NiSource Member shall have the option (but not the obligation) to require each Investor Member to Transfer all of its Membership Interests to the Third Party buyer (the "Drag-Along Buyer") (or to such other Party as the Drag-Along Buyer directs) in accordance with the provisions of this Section 6.5 (such right of the NiSource Member, the "Drag-Along Right").

(b) If the NiSource Member elects to exercise the Drag-Along Right pursuant to Section 6.5(a), then the NiSource Member shall send a written notice to each applicable Investor Member (a "Drag-Along Notice") specifying (i) that such Investor Member is required to Transfer all of its Membership Interests pursuant to this Section 6.5, (ii) the amount and form of consideration payable for such Investor Member's Membership Interests, (iii) the name of the Third Party to which such Investor Member's Membership Interests are to be Transferred (or which is otherwise entitled to direct the disposition thereof at the consummation of the Drag-Along Sale), (iv) any other material terms and conditions of the proposed Transfer and (v) the intended dates on which the NiSource Member will enter into a definitive agreement in respect of such proposed Transfer and consummate such proposed Transfer.

(c) In the event that the NiSource Member elects to exercise the Drag-Along Right, then each Investor Member hereby agrees with respect to all Membership Interests it holds:

(i) in the event such transaction requires the approval of Members, to vote (in person, by proxy or by action by written consent, as applicable) all of its Membership Interests in favor of such Drag-Along Sale;

(ii) to execute and deliver all related documentation and take such other action reasonably necessary to enter into definitive agreements in respect of and to consummate the proposed Drag-Along Sale in accordance with, and subject to the terms of, this Section 6.5; and

(iii) not to deposit its Membership Interests in a voting trust or subject any Membership Interests to any arrangement or agreement with respect to the voting of such Membership Interests, unless specifically requested to do so by the Drag-Along Buyer in connection with a Drag-Along Sale.

(d) Subject to Section 6.5(e), any Transfer of an Investor Member's Membership Interests in a Drag-Along Sale shall be on the same terms and conditions as the proposed Transfer of the NiSource Member's Membership Interests in the Drag-Along Sale. Upon the request of the NiSource Member, each Investor Member shall be required to make customary representations and warranties in connection with the Transfer of such Investor Member's Membership Interests, including as to its ownership and authority to Transfer, free and clear of all Liens, its Membership Interests, and shall indemnify and hold harmless, to the fullest extent permitted by applicable Law, the Drag-Along Buyer against all losses of whatever nature arising out of, in connection with or related to any breach of any representation or warranty made by, or agreements, understandings or covenants of such Investor Member as the case may be, under the terms of the agreements relating to such Transfer of such Investor Member's Membership Interests, in each case not to exceed the equivalent obligations to indemnify and hold harmless the Drag-Along Buyer provided by the NiSource Member; provided, that (i) liability for misrepresentation or indemnity shall (as between the NiSource Member and such Investor Member) be expressly stated to be several but not joint and the NiSource Member and such Investor Member shall not be liable for any breach of covenants or representations or warranties as to the Membership Interests of any other Member and shall not, in any event, be liable for more than its pro rata share (based on the proceeds to be received) of any liability for misrepresentation or indemnity, (ii) such Investor Member shall benefit from any releases of sellers or other provisions in the transaction documentation of general applicability to sellers to the same extent as the NiSource Member and (iii) such Investor Member shall not be obligated to provide indemnification obligations that exceed its proceeds from the Drag-Along Sale.

(e) Any Transfer required to be made by an Investor Member pursuant to this Section 6.5 shall be for consideration consisting of cash or cash equivalents (or a combination thereof). Without the consent of the applicable Investor Member, an Investor Member shall not be required in connection with such Drag-Along Sale to agree to any material indemnification obligations, material, non-customary administrative covenants (including, but not limited to, restrictive covenants (such as non-solicit and non-compete covenants) that would restrict its or its Affiliates' business activities).

(f) At the consummation of the Drag-Along Sale, each Investor Member shall Transfer all of its Membership Interests to the Drag-Along Buyer (or its designee), and the Drag-Along Buyer shall pay the consideration due for such Investor Member's Membership Interest. If either Investor Member has failed, as of immediately prior to the time that the consummation of the Drag-Along Sale would otherwise have occurred, to have taken all actions necessary in accordance with this Agreement to consummate the Transfer of the Membership Interests held by it, then such Investor Member shall be deemed to be in material breach of this Agreement for purposes of Article IV and for all other purposes hereunder, shall be a Defaulting Member, and shall be deemed to have granted (and hereby grants, contingent only on the occurrence of such failure) an irrevocable appointment of any Person nominated for the purpose by the NiSource Member to be such Investor Member's agent and attorney to execute all necessary documentation and instruments on its behalf to Transfer such Investor Member's Membership Interest to the Drag-Along Buyer (or as it may direct) as the holder thereof, in each case consistent with the terms set forth in this Section 6.5.

(g) The NiSource Member shall have a period of 180 days commencing on the delivery of the Drag-Along Notice (such 180-day period, the "Drag Sale Period") to consummate the Drag-Along Sale. If the Drag-Along Sale is not completed prior to the expiration of the Drag Sale Period, then the process initiated by the delivery of the Drag-Along Notice shall be lapsed, and the NiSource Member will be required to repeat the process set forth in this Section 6.5 to pursue any Drag-Along Sale; provided that if a definitive agreement providing for the consummation of such Drag-Along Sale is executed within the Drag Sale Period but such Drag-Along Sale has not been consummated at the expiration of the Drag Sale Period solely as a result of a failure to receive the requisite authorization, approval or consent of any Governmental Body in respect of such Drag-Along Sale, then the Drag Sale Period shall be extended solely to the extent necessary to permit the receipt of all such authorizations, approvals or consents which are in process but have not been received from the relevant Governmental Body as of the original expiration date of the Drag Sale Period and the consummation of the Drag-Along Sale provided for in such definitive agreement; provided, that the NiSource Member shall have used efforts in seeking such authorizations, approvals and consents consistent with its obligations under such definitive agreement(s) in respect thereof.

(h) Notwithstanding the foregoing, the NiSource Member may not exercise the Drag-Along Right or consummate any Drag-Along Sale, without the prior written consent of the BIP Investor Member unless the applicable Drag-Along Sale would result in the Investor Members receiving proceeds resulting in the Investor Members collectively achieving at least a IRR of 10% (the "Investor Return Threshold") and a MOIC of 2.15x (the "MOIC Return Threshold"); provided, that any shortfall in the Investor Members collectively achieving the Investor Return Threshold or the MOIC Return Threshold may be paid by the NiSource Member to the Investor Members in immediately available funds at the closing of the Drag-Along Sale, in which case the prior written consent of the BIP Investor Member shall not be required to exercise the Drag-Along Right or consummate such Drag- Along Sale.

(i) For the avoidance of doubt, the rights conferred to the NiSource Member under this Section 6.5 do not apply in the event of a Change in Control of the NiSource Member.

Section 6.6 Cooperation. The transferring Member acknowledges and agrees that it shall cooperate reasonably to obtain the requisite authorization, approval or consent of any Governmental Body necessary to consummate any Transfers contemplated or permitted by this Article VI. The Members shall have the right in connection with any Transfer of Membership Interests permitted by this Agreement (or in connection with the investigation or consideration of any such potential Transfer) to require the Company to reasonably cooperate with potential purchasers in such prospective Transfer (at the sole cost and expense of the applicable Member or such potential purchasers) by taking such actions reasonably requested by the applicable Member or such potential purchasers to cooperate in such Transfer, including

(a) preparing or assisting in the preparation of due diligence materials and (b) providing such reasonable access to the Company's and each of its Subsidiaries' books, records, properties and other materials (subject, in each case, to the execution of customary confidentiality and non-disclosure agreements and subject to attorney-client privilege) to potential purchasers; provided that no such cooperation by the Company shall be required (i) until the relevant potential purchaser executes and delivers to the Company a customary confidentiality agreement, (ii) to the extent such cooperation would unreasonably interfere with the normal business operations of the Company or any of its Subsidiaries, and (iii) to the extent the provision of any information would (A) conflict with, or constitute a violation of, any applicable Law or Order or cause a loss of attorney-client privilege of the Company or any of its Subsidiaries, (B) in the NiSource Member's reasonable determination, require the disclosure of any information that is proprietary, confidential or sensitive to the NiSource Member or to any member of the Outside Group, or (C) require the disclosure of any information relating to any joint, combined, consolidated or unitary Tax Return that includes the NiSource Member or any other member of the Outside Group or any supporting work papers or other documentation related thereto.

Section 6.7 Blocker Entity.

(a) Notwithstanding anything to the contrary in this Agreement, if an Investor Member is participating in any sale of Membership Interests pursuant to Section 6.3, Tag-Along Sale or Drag-Along Sale or any other Transfer of its Membership Interests, the owners of such Investor Member (or, as applicable, the regarded owner of such Investor Member for U.S. federal income tax purposes) (each, a "Blocker Seller") shall, use commercially reasonable efforts to sell, and the NiSource Member and the Company will use commercially reasonable efforts to structure such sale or transfer such that the Blocker Seller is able to sell, Equity Interests in such Investor Member (or, as applicable, the regarded owner of such Investor Member for U.S. federal income tax purposes), in lieu of selling the Membership Interests held (directly or indirectly) by such Investor Member in exchange for consideration equal to the value of the Membership Interests as determined in such sale pursuant to Section 6.3, Tag-Along Sale or Drag-Along Sale or other Transfer, held (directly or indirectly) by such Investor Member without discount (as appropriately adjusted for any partial sale).

(b) Notwithstanding anything to the contrary in this Agreement, but subject to the last sentence of this Section 6.7(b), the Members shall use reasonable efforts and cooperate in good faith to (i) minimize any tax liabilities of the Company or its Members, including with respect to the structure of each Member's ownership in the Company and in connection with claiming any tax credits or accelerated tax depreciation deductions, and (ii) ensure recoverability of tax expense under any applicable rates approved by the IURC, FERC or such other applicable Governmental Body. In no event shall any Member be required to take any action that would reasonably be expected to result in a material economic, financial or tax consequence on such Member or its Affiliates, as determined by such Member in good faith.

(c) With respect to tax exempt entities which hold a Percentage Interest in the Company, directly or indirectly, the Investor Members shall use commercially reasonable efforts, to the extent requested by the NiSource Member but no more frequently than a quarterly basis, to provide the NiSource Member a reasonable estimate based on information then available to the Investor Member of the estimated amount of Percentage Interest held by such entities in the aggregate, until such time as the applicable Investor Member has no tax-exempt investors in such Investor Member's ownership structure in the Company.

**Article VII
PREEMPTIVE RIGHTS**

Section 7.1 Preemptive Rights. The Company hereby grants to each Member the right to purchase such Member's Preemptive Right Share of all (or any part) of any New Securities that the Company may from time to time issue after the Effective Date (the "Preemptive Right"); provided, however, that the Preemptive Right shall not apply with respect to New Securities issues or to be issued in any public offering or pursuant to failures to fund Additional Funding Requirements or as otherwise specifically provided herein. In the event the Company proposes to undertake an issuance of New Securities (in a single transaction or a series of related transactions), the Company shall give to each Member written notice of its intention to issue New Securities (the "Preemptive Right Participation Notice"), describing the amount and type of New Securities, the cash purchase price and the general terms

upon which it proposes to issue such New Securities. Each Member shall have twenty (20) days from the date of receipt of any such Preemptive Right Participation Notice (the “Preemptive Right Notice Period”) to agree in writing to purchase for cash up to such Member’s Preemptive Right Share of such New Securities for the price and upon the terms and conditions specified in the Preemptive Right Participation Notice by giving written notice to the Company and stating therein the quantity of New Securities to be purchased (not to exceed such Members’ Preemptive Right Share) as well as the maximum amount of New Securities it would purchase. If any Member fails to so respond in writing within the Preemptive Right Notice Period, then such Member shall forfeit the right hereunder to purchase its Preemptive Right Share of such New Securities and the Company will allocate the rights to purchase such New Securities to any other Member that indicated it would purchase New Securities in excess of its Preemptive Right Share based on their relative Preemptive Right Shares. Subject to obtaining the requisite authorization, approval or consent of any Governmental Body, the closing of any purchase by any Member pursuant to this Section 7.1 shall be consummated concurrently with the consummation of the issuance or sale described in the Preemptive Right Participation Notice. The Company shall be free to complete the proposed issuance or sale of New Securities described in the Preemptive Right Participation Notice with respect to any New Securities not elected to be purchased pursuant to this Section 7.1 in accordance with the terms and conditions set forth in the Preemptive Right Participation Notice (except that the amount of New Securities to be issued or sold by the Company may be reduced). If a Member indicates in its response to a Preemptive Right Participation Notice that it shall purchase New Securities but then does not fund such amounts, such Member shall be a Defaulting Member.

Article VIII PROTECTIVE PROVISIONS

Section 8.1 Investor Member Threshold Matters. Notwithstanding anything to the contrary in this Agreement, the Company shall not cause or permit, in each case, so long as the Investor Members’ aggregate Percentage Interest is equal to or greater than the Investor Consent Threshold (except with respect to subclauses (a)–(g) and (i), in which case so long as the Investor Members’ aggregate Percentage Interest is at least 4.9%), and no Investor Member is a Defaulting Member, without the prior written consent of the BIP Investor Member (except that no such written consent shall be required to the extent that such matter is necessary to comply with applicable Law or Order or is in response to an Emergency Situation):

- (a) make an election or take any other action that results in a change in the tax classification of the Company or any of its Subsidiaries, with respect to its Subsidiaries only if such change adversely affects the BIP Investor Member;
- (b) any non-*pro rata* repurchase or redemption of any Equity Interests issued by the Company;
- (c) any (i) issuance of any class of Equity Interest in the Company, other than pursuant to Sections 1.9, 5.1, Section 7.1 or as otherwise specifically contemplated herein or (ii) change to the existing rights or obligations of any class of Equity Interest of the Company if such change would have a disproportionate material adverse impact on any Member in a manner different from the NiSource Member;
- (d) the filing of a petition seeking relief, or the consent to the entry of a decree or order for relief in an involuntary case, under the bankruptcy, rearrangement, reorganization or other debtor relief Laws of the United States or any state or any other competent jurisdiction or a general assignment for the benefit of its creditors by the Company or any of its Subsidiaries of all or substantially all of the assets of the Company and its Subsidiaries;
- (e) the conversion of the Company or GenCo from its current legal business entity form to any other business entity form (e.g., the conversion of the Company from a Delaware limited liability company to a Delaware corporation);
- (f) the listing of any Equity Interests of the Company or its Subsidiaries on any stock exchange (other than any spin off, split off or similar transaction of the Company, the NiSource Member or GenCo, or any of their Affiliates, which, for the avoidance of doubt, shall be subject to Sections 5.1(e) or 6.5 and the Spin Return Threshold);

(g) any amendment or modification to any Organizational Document of the Company or any Subsidiary of the Company, other than (i) ministerial amendments thereto or (ii) amendments thereto that are not disproportionately adverse to the BIP Investor Member as compared to any other holder of Equity Interests of the Company;

(h) the transfer, sale or other disposition, whether by the way of asset sale, stock sale, merger, or otherwise, of (i) all or substantially all of the assets of the Company Group, taken as a whole on a consolidated basis, or (ii) assets of the Company's Subsidiaries having a Fair Market Value in excess of 2.5% of the Qualifying Core Asset Base in the aggregate in any transaction or series of related transactions, other than Qualifying Core Assets and Excluded Transactions (it being understood, for the avoidance of doubt, that this Section 8.1(h) shall not be deemed to restrict a transfer, sale or other disposition of the equity of the Company) and other than pursuant to Article VI or a Change in Control of the Company, or the NiSource Member or as set forth below;

(i) the transfer, sale, issuance, or other disposition of any Equity Interests in GenCo or in any Subsidiary of the Company that directly or indirectly holds any Equity Interests in GenCo to any Person that is not the Company or one of its wholly-owned Subsidiaries;

(j) any new agreements or amendments to existing agreements, among the Company or any of its Subsidiaries, on the one hand, and any Member or any of their respective Affiliates (other than the Company or any of its Subsidiaries), on the other hand, which such agreement (or series of related transactions) are entered into after the Effective Date, other than (x) those that (i) are on an arms-length basis and (ii) involve revenues or expenditures of less than \$55,000,000.00 per Contract or series of related transactions individually or less than \$112,500,000.00 in the aggregate, subject to an annual increase by the CPI Escalator, for any fiscal year for all such affiliate transactions (it being acknowledged and agreed that no prior written consent of the BIP Investor Member will be required with respect to any amendments to any affiliate transaction made in the ordinary course of business unless to the extent such amendment would have a disproportionately adverse effect on the Company Group) in any material respect or (y) the GenCo Offtake Agreements or such other agreements by and among the Company or any of its Subsidiaries, on the one hand, and NHII or any of its Subsidiaries, on the other hand, which are reasonably necessary (as determined by the Board in good faith) for the Company's and its Subsidiaries' performance of any obligations under any GenCo Offtake Agreements (including with respect to the transfer or sale of Zonal Resource Credits or other similar capacity credits to or from NIPSCO or its Subsidiaries to or from the Company or its Subsidiaries) or otherwise be required for NIPSCO's performance of, or compliance with, any obligations arising under any "special contract" entered into by NIPSCO and a large load or hyperscale customer or similar arrangement (including any tariff), which in each case are as submitted to the IURC and/or otherwise consistent with applicable Law at such time, including any applicable IURC rules and regulations and, in each case, which are on an arm's-length basis;

(k) the acquisition by the Company or any of the Company's Subsidiaries of any Equity Interests or assets of any Person or the entry into joint ventures, in each case, having a Fair Market Value in excess of 2.5% of the Qualifying Core Asset Base in the aggregate in any calendar year, other than in connection with Qualifying Core Assets or Excluded Transactions;

(l) any capital expenditure by the Company or its Subsidiaries, that is in excess of 1.0% of the Qualifying Core Asset Base in any calendar year and is not made (i) in connection with a Qualifying Core Asset, (ii) reasonably necessary to fund an Emergency Expenditures, or (iii) an Excluded Transaction;

(m) incurring long-term Indebtedness (other than the refinancing of existing Indebtedness on commercially reasonable terms consistent with current market conditions as determined by the Board in good faith) by the Company or its Subsidiaries, if after giving pro forma effect to such incurrence and the application of the proceeds therefrom, the Company's and its Subsidiaries' Debt-to-Capital Ratio would exceed 0.7;

(n) making any political or charitable contribution made by or on behalf of the Company or any of its Subsidiaries to any Governmental Body or any official, representative or staff thereof, including

any community leaders or elected officials, in excess of \$250,000 individually or \$1,000,000 in the aggregate in a fiscal year; and

(o) entering into any binding agreement or arrangement by the Company or any of its Subsidiaries to effect any of the foregoing actions.

Notwithstanding the foregoing, no BIP Investor Member approval shall be required with respect to any spin off, split off or similar transaction of the Company, the NiSource Member or GenCo, or any of their Affiliates; provided, that any such transaction must satisfy the requirements of Section 5.1(e) or Section 6.5 and the Spin Return Threshold.

Section 8.2 Consultation Matters. For so long as (x) the Investor Members' aggregate Percentage Interest is at least 9.9% and (y) no Investor Member is a Defaulting Member, the Company (and, as applicable, the Board) shall use reasonable efforts to consult in good faith with the BIP Investor Member prior to the Company undertaking, or causing or permitting any of its Subsidiaries to undertake, the following matters (except as would be impracticable in respect of a particular action that the Board reasonably believes to be necessary or appropriate to comply with applicable Law, Order or in response to an Emergency Situation):

(a) appointing or replacing the President;

(b) establishing or materially amending, or material deviating from the then-current plan or budget of the Company and its Subsidiaries; provided, that the Company (and, as applicable, the Board) the NiSource Member and the Parent shall (i) provide to the BIP Investor Member a draft of the business plan and budget of the Company and its Subsidiaries for a given fiscal year no later than November 10 of the prior fiscal year, which budget shall include quarterly fiscal projections, (ii) schedule and attend a meeting among representatives of the Company, the NiSource Member, the Parent and the BIP Investor Member, including the Chief Financial Officer and Head of Regulatory Affairs of the Parent, no later than November 24 of the prior fiscal year, to discuss the draft business plan and budget, (iii) schedule and attend a meeting between the Chief Executive Officer of the Parent and the Global Head of Infrastructure of Blackstone Inc., within 5 Business Days of a written request by the BIP Investor Member, to discuss the draft business plan and budget as well as any changes proposed by BIP Investor Member and (iv) consider the BIP Investor Member's comments to the business plan and budget in good faith;

(c) material decisions relating to the conduct (including the settlement) of any litigation, administrative, or criminal proceeding to which the Company or any of its Subsidiaries is a party where (i) it is reasonably expected that the liability of the Company and its Subsidiaries would exceed \$75,000,000 (as adjusted by the CPI Escalator) (solely with respect to litigation proceedings), (ii) such proceeding would have material reputational damage on the Company or its Subsidiaries, or (iii) such proceeding would reasonably be expected to have a material and adverse effect on the BIP Investor Member or any of its Affiliates (other than in its or (if applicable, their) capacity as an investor in the Company); provided, that, for the avoidance of doubt, the foregoing shall not be applicable to any ordinary course regulatory proceedings (including rate cases) that do not involve claims of criminal conduct or intentional violations of applicable Law; and

(d) entering into or materially amending any Genco Offtake Agreement or related support agreements, in which case such consultation shall include the Company (and, as applicable, the Board) using reasonable efforts to keep the BIP Investor Member reasonably informed regarding the negotiation of any GenCo Offtake Agreements or related support agreements and to consult in good faith with the BIP Investor Member regarding the form, material terms, structuring and implementation of any such GenCo Offtake Agreements or related support agreements, including any material changes to such GenCo Offtake Agreement or related support agreement.

Section 8.3 Indebtedness. Each of the Company and its Subsidiaries shall use commercially reasonable efforts to incur Indebtedness, both intercompany and with respect to any Third Party, to support its operations, working capital and capital investments in accordance with the informational compliance filings provided by GenCo to the IURC.

Section 8.4 Actions by the Investor Directors on behalf of the BIP Investor Member. Where any action requires the consent of the BIP Investor Member pursuant to Section 8.1, the Investor Directors shall, unless the BIP Investor Member indicates in writing to the NiSource Member otherwise, have the authority to provide such consent on behalf of the BIP Investor Member at any meeting of the Board called to discuss such matters, and the Company, the other Members and the other Directors shall be entitled to rely on such action of the Investor Directors as an action of the BIP Investor Member with such action being binding upon the BIP Investor Member.

Section 8.5 Additional Actions. The NiSource Member and Investor Members further agree to the additional actions set forth on Schedule 2.

Section 8.6 Acknowledgement of Purpose of Provisions. It is hereby acknowledged and agreed by the Parties that the rights of the Investor Members set forth in this Article VIII are protection mechanisms for each Investor Member acting in its capacity as an investor in the Company and are not for purposes of, and should not be construed or otherwise interpreted as, providing either Investor Member or any of its Representatives or Affiliates with the ability to take any action that would constitute exercising substantial influence or control over the Company or any of its Subsidiaries or would otherwise provide either Investor Member or any of their respective Representatives or Affiliates with any right to direct the operation of the business of the Company or any of its Subsidiaries.

Article IX

OTHER COVENANTS AND AGREEMENTS

Section 9.1 Books and Records.

(a) The Company shall keep and maintain, or cause to be kept and maintained, books and records of accounts, taxes, financial information and all matters pertaining to the Company and its Subsidiaries at the offices and place of business of the Company in a commercially reasonable manner consistent with the manner in which similar books and records are kept and maintained by other members of the Outside Group. Each Member (other than any Defaulting Member) and its duly authorized Representatives shall have the right to, at reasonable times during normal business hours, upon reasonable notice, under supervision of the Company's personnel and in such a manner as to not unreasonably interfere with the normal operations of any member of the Company Group, visit and inspect the books and records of the Company Group, and, at its expense, make copies of and take extracts from any books and records of the Company Group; provided, that, in the case of an Investor Member, any Person gaining access to such information regarding the Company Group pursuant to this Section 9.1 shall agree to hold in strict confidence, not make any disclosure of, and not use for purposes other than good faith administration of such Investor Member's continuing investment, all information regarding any member of the Company Group that is not otherwise publicly available.

(b) Notwithstanding the foregoing, the Company shall not be obligated to provide to either Investor Member any record or information (i) relating to the negotiation and consummation of the transactions contemplated by this Agreement, including confidential communications with Representatives or Advisors, including legal counsel, representing the Company or any of its Affiliates, (ii) that is subject to an attorney-client or other legal privilege, (iii) that, in the NiSource Member's reasonable determination, are proprietary, confidential or sensitive to the NiSource Member or to any other member of the Outside Group, (iv) relating to any joint, combined, consolidated or unitary Tax Return that includes the NiSource Member or any other member of the Outside Group or any supporting work papers or other documentation related thereto if such work papers or documentation includes the information of the NiSource Member or Outside Group, or (v) the provision of which would violate any applicable Law or Order; provided, with respect to (ii) and (iv) above that the Company shall use commercially reasonable efforts to develop an alternative to make such information available, including to make redactions to any such material and provide such redacted materials to such Investor Member.

(c) Each Member shall reimburse the Company for all reasonable, documented, out-of-pocket costs and expenses incurred by the Company in connection with such Member's exercise of its inspection and information rights pursuant to this Section 9.1.

Section 9.2 Financial Reports. The Company shall provide, or otherwise make available, to any Member (unless such Member is a Defaulting Member):

(a) on an annual basis, within 120 days after the end of each fiscal year, an unaudited consolidated balance sheet, statement of operations and statement of cash flow of GenCo and its Subsidiaries;

(b) on a quarterly basis, within 60 days after the end of each fiscal quarter, an unaudited consolidated balance sheet and related quarter and year to date statement of operation and related quarter and year to date statement of cash flow of GenCo and its Subsidiaries;

(c) on a monthly basis, within 30 days after the end of each month-end, an unaudited income statement as readily available of GenCo and its Subsidiaries and related financial information prepared in the ordinary course;

(d) on an annual basis (or more frequently, if applicable), as soon as reasonably practicable after the approval thereof by the Board, the annual budget and business plan for GenCo and its Subsidiaries;

(e) on an annual basis, as soon as reasonably practicable after the approval thereof by the Board, financial forecasts for GenCo and its Subsidiaries, which shall be in such manner and form as approved by the Board, and which shall include a projection of income and a projected cash flow statement for each fiscal quarter in such fiscal year and a projected balance sheet as of the end of each fiscal quarter in such fiscal year;

(f) (i) within 45 days after the end of each fiscal year, an estimated Schedule K-1 for the immediately preceding taxable year based on best-available information to date and depreciation will be subject to change based on final year end financial reporting results and (ii) not less than 45 days prior to the due date, including extensions, for the filing of the Company's federal information return for the immediately preceding taxable year, a final Schedule K-1, along with copies of all other federal, state and local income tax returns or reports filed by the Company for the previous year, as may be required as a result of the operations of the Company, and a schedule of Company book tax differences for the immediately preceding year;

(g) each Investor Member shall promptly upon request by the NiSource Member provide the following information: (i) Form SS-4/IRS determination letter and Form 8832 Entity Classification Election (if applicable) and (ii) Form W-9; and

(h) promptly, upon reasonable notice, any information that is reasonably requested by any Member in order to manage its regulatory or tax affairs or make filings with Governmental Bodies, including but not limited to Federal and Indiana corporate tax returns and financial statements (whether or not audited) for either Investor Member (or the regarded owner of either Investor Member if such Investor Member is a disregarded entity for tax purposes).

Section 9.3 Other Business; Corporate Opportunities.

(a) To the extent permitted by applicable Law, any Member and any Affiliate of any Member may engage in, possess an interest in or otherwise be involved in other business ventures of any nature or description, independently or with others, similar or dissimilar to the businesses of the Company Group, and neither the Company nor any other Member shall have any rights by virtue of this Agreement in and to such independent ventures or the income or profits derived therefrom, and the pursuit of any such venture, even if competitive with the businesses of the Company Group, shall be deemed not to be wrongful or improper so long as it is consistent with all Laws and Orders applicable to the Company and its Subsidiaries.

(b) The Company and each Member expressly acknowledge and agree that, (i) neither the Members nor any of their respective Affiliates or Representatives shall have any duty to communicate or present an investment or business opportunity to the Company in which the Company may, but for the provisions of this Section 9.3, have an interest or expectancy (a "Corporate Opportunity"), and (ii) neither the Members nor any of their respective Affiliates or Representatives (even if such Person is also an officer or Director of the Company) shall be deemed to have breached any duty or obligation to the Company by reason of the fact that such Person pursues or acquires a Corporate Opportunity for itself or

directs, sells, assigns or transfers such Corporate Opportunity to another Person or does not communicate information regarding such Corporate Opportunity to the Company. The Company and each Member expressly renounce any interest in Corporate Opportunities and any expectancy that a Corporate Opportunity will be offered to the Company.

(c) Notwithstanding anything to the contrary contained in this Section 9.3, for so long as the Investor Members are Affiliated Members and the Investor Members' aggregate Percentage Interest is equal to or greater than 14.9%, the Company and/or its Subsidiaries (including for the avoidance of doubt, GenCo) and NHII and/or its Subsidiaries (including for the avoidance of doubt, NIPSCO) shall be the exclusive vehicles for all power, storage and generation requirements for customers within NIPSCO's service territory, which, for the avoidance of doubt, will include the State of Indiana to the extent included within NIPSCO's service territory as of the applicable time, for which a "special contract" is required except to the extent (i) necessary to comply with applicable Law or Order or (ii) consented to by BIP Investor Member; provided, that, to the extent required by applicable Law or Order, the Parties will use their reasonable efforts to give effect to the foregoing exclusivity to the maximum extent permitted, and if any portion of this Section 9.3 is prohibited or unenforceable, it shall be enforced to the fullest lawful extent and otherwise deemed modified only as necessary to be valid, with the remainder continuing in full force and effect.

Section 9.4 Compliance with Laws.

(a) The Company shall and shall cause its Subsidiaries to use their respective commercially reasonable efforts to procure that the Company and its Subsidiaries and Company Group's respective Representatives shall not in the course of their actions for, or on behalf of, any member of the Company Group:

(i) offer promise, provide or authorize the provision of any money, property, contribution, gift, entertainment or other thing of value, directly or knowingly indirectly, to any government official, to unlawfully influence official action or secure an improper advantage, or to unlawfully encourage the recipient to improperly influence or affect any act or decision of any Governmental Body, in each case, in order to assist any member of the Company Group in obtaining or retaining business, or otherwise act in violation of any applicable Anti-Corruption Laws;

(ii) violate any applicable Anti-Money Laundering Laws; or

(iii) engage in any unlawful dealings or transactions with or for the benefit of any Sanctioned Person or otherwise violate Sanctions.

(b) The Company shall promptly notify the Members of (i) any allegations of material misconduct by any member of the Company Group or any actions, suits or proceedings by or before any Governmental Body to which any member of the Company Group becomes a party, or to which the Company becomes aware that any Representative of the Company Group (in relation to such Representative's actions for, or on behalf of, any member of the Company Group) is a party, in each case, relating to any material breach or suspected material breach of any applicable Anti-Corruption Laws, Anti-Money Laundering Laws, or Sanctions or (ii) any fact or circumstances of which it becomes aware that would reasonably be expected to result in a breach of this Section 9.4.

Section 9.5 Non-Solicit. Without the prior written consent of the Company, during the term of this Agreement, each Investor Member shall not, shall cause its Affiliates not to, and shall use its reasonable best efforts to procure that other Persons in which it is invested do not, solicit for employment, hire or engage as a consultant any individual who is serving in any position within the then-current NiSource Leadership Team; provided, that this Section 9.5 shall not prohibit any Person from issuing general public solicitations not specifically targeted at the then-current NiSource Leadership Team or from hiring or engaging any Person responding to such general solicitations.

Section 9.6 Confidentiality.

(a) Each Member shall, and shall cause its Representatives to, keep confidential and not divulge any information (including all budgets, business plans and analyses) concerning the Company and its Subsidiaries, including their respective assets, business, operations, financial condition and prospects, or with respect to another Member of this Agreement ("Confidential Information"), and to use such

Confidential Information only in connection with the operation of the Company and its Subsidiaries or such Member's administration of its investment in the Company; provided that nothing herein shall prevent any Member from disclosing such Confidential Information (i) upon the Order of any court or administrative agency, (ii) upon the request or demand of any Governmental Body having jurisdiction over such party, (iii) to the extent compelled by legal process or required pursuant to binding requirement of any Governmental Body, (iv) to the other Parties, (v) to such party's Representatives that in the reasonable judgment of such party need to know such Confidential Information, (vi) to any potential Permitted Transferee in connection with a proposed Transfer of Membership Interests from a Member so long as such transferee agrees to be bound by the provisions of this Section 9.6 as if a Member, or (vii) to actual and prospective limited partners of such Member or its Affiliates in connection with reporting requirements or fundraising efforts; provided, further, that in the case of clauses (i), (ii) or (iii), such Member shall prior to making any disclosure seek a protective order or other relief to prevent or reduce the scope of such disclosure, to the extent legally permissible, notify the other Parties of the proposed disclosure as far in advance of such disclosure as practicable and use reasonable efforts to ensure that any Confidential Information so disclosed is accorded confidential treatment, when and if available; provided, further, that in the cases of clauses (v) through (vii), such party receiving any Confidential Information is bound to an obligation of confidentiality no less stringent than that contained in this Agreement including such other protective provisions to protect the misuse of material non-public information.

(b) The restrictions in Section 9.6(a) shall not apply to information that (i) is or becomes generally available to the public other than as a result of a disclosure by a Member or any of its Representatives in violation of this Agreement, (ii) is or has been independently developed or conceived by such Member or its Affiliates without use of the Company's or any of its Subsidiaries' Confidential Information or (iii) becomes available to the receiving Member or any of its Representatives on a non-confidential basis from a source other than the Company or any of its Subsidiaries, any other Party or any of their respective Representatives; provided, that such source is not known by the recipient of the information to be bound by a confidentiality agreement with the disclosing party or any of its Representatives.

(c) Each Party shall inform any Representatives to whom it provides Confidential Information that such information is confidential and instruct them (i) to keep such Confidential Information confidential and (ii) not to disclose Confidential Information to any Third Party (other than those Persons to whom such Confidential Information has already been disclosed in accordance with the terms of this Agreement). The disclosing Party shall be responsible for any breach of this Section 9.6 by the Person to whom the Confidential Information is disclosed.

(d) The restrictions in Section 9.6(a) shall not restrict any Member and its Affiliates from disclosing any Confidential Information required to be disclosed under applicable securities Laws or the rules of any stock exchange on which any of their securities are traded.

(e) Notwithstanding anything herein to the contrary, the provisions of this Section 9.6 shall survive the termination of this Agreement for a period of three (3) years and, with respect to each Member, shall survive for a period of three (3) years following the date on which such Member is no longer a Member. The provisions of this Section 9.6 shall supersede the provisions of any non-disclosure agreements entered into by the Company (or its Affiliates, including the NiSource Member) and any of the Members (or their respective Affiliates) with respect to the transactions contemplated hereby prior to the Effective Date.

Section 9.7 Expenses. Except as otherwise expressly provided herein, all costs and expenses, including fees and disbursements of Representatives and other Advisors, incurred in connection with this Agreement and the transactions contemplated hereby, shall be paid by the Party incurring such costs and expenses. Notwithstanding the foregoing, should any litigation be commenced between the Parties or their Representatives concerning this Agreement or the rights, duties, or obligations hereunder, the Party or Parties prevailing in such proceeding shall be entitled, in addition to any other relief granted, to the reasonable attorneys' fees and other litigation costs incurred by reason of such litigation.

Section 9.8 Obligations in Respect of Financings.

(a) Subject to Section 9.8(b), during the term of this Agreement, the NiSource Member and the Company shall cooperate with each Investor Member as reasonably requested by such Investor

Member in connection with any Debt Financing. Such assistance shall include (i) providing to such Investor Member such information as may be reasonably necessary in connection with the Debt Financing and any related credit-rating process in accordance therewith, and (ii) taking such other actions as are reasonably requested by such Investor Member to facilitate the consummation of any Debt Financing and any related credit-rating process in accordance therewith (including providing customary authorization letters authorizing the distribution of information to prospective financing sources, subject to customary terms and conditions). Such cooperation will include cooperating with the due diligence requirements of the debt financing sources, including the furnishing of customary financial and operational information about the Company reasonably requested by the Investor Members or the debt financing sources solely for diligence and underwriting; causing management to participate in a reasonable number of customary presentations; providing access (at reasonable times upon reasonable notice) to senior management; cooperating with the Investor Member to support the Investor Member's production of any customary third-party reports reasonably required in connection with such financing including engineering, insurance broker or similar reports; and providing copies of permits, material project contracts to which the Company or any of its Subsidiaries is party and any progress reports and other notices received under or in connection with such material project contracts, in each case, as reasonably requested in connection with any such debt financing. Further, each of the NiSource Member and the Company shall have its reasonable, documented and invoiced out-of-pocket costs and expenses incurred in providing such cooperation and assistance pursuant to this Section 9.8 reimbursed by the Investor Member pursuing the applicable Debt Financing.

(b) Notwithstanding anything in Section 9.8(a) or this Agreement to the contrary, the cooperation requested by either Investor Member pursuant to Section 9.8(a) shall not (i) unreasonably interfere with the ongoing operations of the NiSource Member or its Subsidiaries, or (ii) require the NiSource Member or any of its Subsidiaries (other than the Company) to (A) pay any commitment or other similar fee, (B) have or incur any liability or obligation in connection with any Debt Financing, including under any agreement or any document related to any Debt Financing, other than any such documents that are customary in connection with such Debt Financing as set forth in Section 9.8(a), (C) commit to taking any action (including entering into any Contract) or to otherwise execute any definitive agreement in connection with any Debt Financing, or (D) take any action that would conflict with, violate or breach or result in a violation or breach of or default under any Contract, this Agreement or any other document contemplated hereby or any Law or regulatory requirements. In no event shall the Company or NiSource Member be required to provide information relating to the transactions contemplated hereby or with any other Person in connection with any possible sale or transfer of assets or equity of the Company and its Subsidiaries, any information subject to the attorney-client privilege or any confidential or sensitive information, or relating to any Tax Return; provided, that, the Company and NiSource Member will use commercially reasonable efforts to redact such materials to remove any such confidential or sensitive information to provide to the Investor Member.

Section 9.9 Credit Support. For so long as there are (a) any guarantees, credit support, letters of credit or financial assurances of a member of the Outside Group related to support obligations of the Company Group, each Member shall pay the portion equal to its Percentage Interest of any payment or draw request on such credit support facilities on or before the applicable payment date required or (b) any guarantees, credit support, letters of credit or financial assurances of the Company or any of its Subsidiaries related to support obligations of a member of the Outside Group, the NiSource Member shall pay all such payments on or before the applicable payment date required. If a Member does not make a payment in accordance with the above, the Company may issue a Capital Call Request Notice in accordance with Section 5.1 for such amount from the applicable Member. For the avoidance of doubt, the failure to make the payment in clauses (a) or (b) prior to a Capital Call Request Notice shall not be an Event of Default and the failure to fund pursuant to a Capital Call Request Notice shall be treated in accordance with Section 5.1. Notwithstanding the foregoing, if the VCOC Investor Member fails to make its payment in accordance with this Section 9.9, the BIP Investor Member shall be obligated to make such payment.

Article X TAX MATTERS

Section 10.1 Tax Classification. The Parties intend that the Company be classified as a partnership for U.S. federal income (and applicable state and local) Tax purposes. Without limiting

Section 8.1(a), neither the Company nor any Member shall make any election to change the tax classification of the Company or otherwise take any action inconsistent with such intended tax classification without the consent of the Board (or its designee).

Section 10.2 Partnership Representative.

(a) The NiSource Member is hereby designated the “Partnership Representative” within the meaning of Code Section 6223(a) of the Company. The Partnership Representative shall, if required, designate from time to time a “designated individual” to act on behalf of the Partnership Representative, and such designated individual shall be subject to replacement by the Partnership Representative in accordance with the Code and Treasury Regulations. If any state or local tax law provides for a tax matters partner, partnership representative, or person having similar rights, powers, authority, or obligations, the Partnership Representative shall also serve in such capacity. The Partnership Representative is authorized to represent the Company before the Internal Revenue Service and any other governmental agency with jurisdiction, make all decisions regarding permitted elections under the Code, Treasury Regulations, and other state and local tax law with respect to tax proceedings; provided, however, the Partnership Representative shall not enter into any settlement or similar agreement without the consent of the Board (such consent not to be unreasonably withheld, conditioned, or delayed). All Members (and former Members) agree to cooperate with, and to do and refrain from doing any or all things reasonably required by the Partnership Representative in connection with the conduct of all such proceedings or to otherwise allow the Company and the Partnership Representative to comply with the partnership audit provisions of the Code, Treasury Regulations, and similar state and local law. All Members shall cooperate in good faith to amend this Section 10.2 or other provisions of this Agreement as necessary to reflect any statutory amendments or the promulgation of Treasury Regulations or other administrative authority promulgated under the Partnership Audit Rules so as to, to the extent possible, preserve the relative rights, duties, and obligations of the Members hereunder. The Company shall, to the fullest extent permitted by law, reimburse and indemnify the Partnership Representative for all third-party expenses (including legal and accounting fees), claims, liabilities, losses, and damages incurred as the Partnership Representative in connection with any examination, administrative, or judicial proceeding, or otherwise acting in its capacity as Partnership Representative.

(b) Notwithstanding anything to the contrary in this Agreement, each Member (including, for purposes of this Section 10.2, any Person who is or becomes a Member but who for any reason ceases to be a Member) (i) hereby covenants to treat each item of income, gain, loss, deduction, or credit attributable to the Company in a manner consistent with the treatment of such income, gain, loss deduction, or credit on the tax return of the Company or as determined in a notice of final partnership adjustment pursuant to Section 6226 of the Code, (ii) hereby agrees to indemnify and hold harmless the Company from such Member’s share of any tax and any penalties, interest, and additions to tax attributable to any adjustment to the income, gain, loss, deduction, or credit of the Company pursuant to Section 6226 of the Code, and (iii) hereby agrees to take all other actions as the Partnership Representative may reasonably direct with respect to the Member’s (or, in respect of the Member, the Company’s) tax liabilities, which shall not include filing an amended return for any “reviewed year” to account for all adjustments under Section 6225(a) of the Code properly allocable to the Member as provided in and otherwise contemplated by Section 6225(c) of the Code and any Treasury Regulations that may be promulgated thereunder. If the Company or any other entity in which the Company holds an interest is obligated to pay any amount to a governmental agency or body or to any other Person (or otherwise makes a payment) of any taxes arising under a federal, state, or local tax audit or other proceeding and the Partnership Representative determines that all or a portion of such payment is specifically attributable to a Member (or former Member), then such Member (or former Member) shall reimburse the Company in full for the entire amount paid (including any interest, penalties, and expenses associated with such payment). The obligations of a Member under this Section 10.2 shall survive such Member’s sale or other disposition of its interests in the Company and the termination, dissolution, liquidation, or winding up of the Company.

(c) The Partnership Representative (i) shall keep the Investor Members reasonably informed of any material tax audit, settlement or proceeding and (ii) shall not settle or otherwise compromise a material tax audit, settlement or proceeding that would have a material adverse impact on either Investor Member, without the BIP Investor Member’s prior written consent (such consent not to be unreasonably withheld, conditioned, or delayed).

Section 10.3 Tax Elections. Except as otherwise provided by this Agreement, all material elections and decisions required or permitted to be made by the Company under any applicable tax law shall be determined by the NiSource Member; provided however, that any election with respect to taxes that is disproportionately materially adverse to either Investor Member shall require the BIP Investor Member's prior consent (such consent not to be unreasonably withheld, conditioned, or delayed). The elections shall include, but not be limited to, the following:

(a) Upon the written request of a Member, the Company may make the election under Section 754 of the Code in accordance with applicable regulations thereunder for the Company and each applicable Subsidiary;

(b) To the extent permitted under Section 706 of the Code, to elect the calendar year as the Company's taxable year and, (i) for clarity, to the extent the Company is permitted to adopt the calendar year, no other year shall be adopted as the taxable year and (ii) to the extent any additional filings or elections are required, to make such required filings or elections;

(c) To elect the accrual method of accounting;

(d) To elect to amortize any organizational expenses of the Company ratably over a period of one hundred eighty (180) months as permitted by Section 709(b) of the Code, and to elect to deduct the start-up expenditures of the Company as permitted by Section 195(b) of the Code;

(e) If "bonus depreciation" is available with respect to qualified property, the NiSource Member shall make the election described in Section 168(k)(7) of the Code to opt out of "bonus depreciation" for the taxable year during which the placed in service date occurs;

(f) To the extent permitted by law, to elect to apply the de minimis safe harbor under Treasury Regulations Section 1.263(a)-1(f);

(g) To the extent permitted under Code Section 461(h)(3), to elect the adoption of the exception for certain recurring items;

(h) To the extent permitted under Code Section 461(c), to elect to ratably accrue real property taxes; and

(i) To elect under Code Section 163(j) to be treated as an excepted trade or business.

Section 10.4 Cooperation. Each Investor Member shall, and shall cause its Affiliates to, provide to the NiSource Member and its Subsidiaries (including the Company and its Subsidiaries), and the NiSource Member and the Company shall, and shall cause their Affiliates to, provide to each Investor Member, in each case, such cooperation, documentation and information as any of them reasonably may request in connection with (a) filing any Tax Return, amended Tax Return or claim for refund, (b) determining a liability for Taxes or (c) preparing for or conducting any Tax audits, examinations or other proceedings by any taxing authority of any Governmental Body.

Section 10.5 Withholding. The Company may withhold and pay over to the United States Internal Revenue Service (or any other relevant Tax authority) such amounts as it is required to withhold or pay over, pursuant to the Code or any other applicable Tax Law, on account of a Member, including in respect of distributions made pursuant to Section 5.2 or Section 5.3, and, for the avoidance of doubt, the amount of any such distribution or other payment to a Member shall be net of any such withholding. To the extent that any amounts are so withheld and paid over, such amounts shall be treated as paid to the Person(s) in respect of which such withholding was made. For all purposes under this Agreement, any amounts withheld or paid with respect to a Member pursuant to this Section 10.5 shall offset any distributions to which such Member is entitled concurrently with such withholding or payment and shall be treated as having been distributed to such Member pursuant to Section 5.2 or Section 5.3 at the time such offset is made. To the extent that the cumulative amount of such withholding or payment exceeds the distributions to which such Member is entitled concurrently with such withholding or payment, the amount of such excess shall be promptly paid to the Company by the Member on whose behalf such withholding is required to be made; provided, however, that any such payment shall not be treated as a Capital Contribution and shall not reduce the amount that a Member is otherwise obligated to contribute

to the Company. To the extent that a Member claims to be entitled to a reduced rate of, or exemption from, a withholding Tax pursuant to an applicable income Tax treaty, or otherwise, such Member shall furnish the Company with such information and forms as such Member may be required to complete where necessary to comply with any and all Laws and regulations governing the obligations of withholding Tax agents, and the Company shall apply such reduced rate of, or exemption from, withholding Tax as reflected on such information and forms that have been provided by such Member. Each Member agrees that if any information or form provided pursuant to this Section 10.5 expires or becomes obsolete or inaccurate in any respect, such Member shall update such form or information.

Section 10.6 Certain Representations and Warranties. Each Member represents and warrants that any such information and forms furnished by such Member shall be true and accurate and agrees to indemnify the Company from any and all damages, costs and out-of-pocket expenses resulting from the filing of inaccurate or incomplete information or forms relating to such withholding Taxes.

Article XI

LIABILITY; EXCULPATION; INDEMNIFICATION

Section 11.1 Liability; Member Duties. The debts, obligations and liabilities of the Company, whether arising in contract, tort or otherwise, shall be solely the debts, obligations and liabilities of the Company, and no Covered Person shall be obligated personally for any such debt, obligation or liability of the Company solely by reason of being a Covered Person. Each Member acknowledges and agrees that each Member, in its capacity as a Member, may decide or determine any matter subject to the approval of such Member pursuant to any provision of this Agreement in the sole and absolute discretion of such Member, and in making such decision or determination such Member shall have no duty, fiduciary or otherwise, to any other Member or to the Company Group, it being the intent of all Members that such Member, in its capacity as a Member, has the right to make such determination solely on the basis of its own interests.

Section 11.2 Exculpation. To the fullest extent permitted by applicable Law, no Covered Person shall be liable to the Company or any other Covered Person for any loss, damage or claim incurred by reason of any act or omission performed or omitted by such Covered Person in good faith on behalf of the Company and in a manner reasonably believed to be within the scope of the authority conferred on such Covered Person by this Agreement, except that a Covered Person shall be liable for any such loss, damage or claim incurred by reason of such Covered Person's fraud or willful misconduct.

Section 11.3 Indemnification. The Company shall indemnify, defend and hold harmless any Person who was or is a party or is threatened to be made a party to any threatened, pending or completed actions, suits or proceedings by reason of the fact that such Person is or was a Director or officer of the Company, or is or was a Director or officer of the Company serving at the request of the Company as a director, officer or agent of another limited liability company, partnership, joint venture, trust or other enterprise, against expenses (including attorneys' and experts' fees), judgments, settlements, penalties and fines actually and reasonably incurred by him or her in connection with the defense or settlement of such, action, suit or proceeding if he or she acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the Company; and, with respect to any criminal action or proceeding, either he or she had reasonable cause to believe such conduct was lawful or no reasonable cause to believe such conduct was unlawful; provided, however, for the avoidance of doubt, this Section 11.3 shall not apply with respect to any such actions between the Company and such Person.

Section 11.4 Authorization. To the extent that such present or former Director or officer of the Company has been successful, on the merits or otherwise, in the defense of any action, suit or proceeding referred to in Section 11.3, or in the defense of any claim, issue or matter therein, the Company shall indemnify him or her against expenses (including attorneys' fees) actually and reasonably incurred by him or her in connection therewith. Any other indemnification under Section 11.3 shall be made by the Company only as authorized in the specific case, upon a determination that indemnification of the present or former Director or officer is permissible in the circumstances because such present or former Director or officer has met the applicable standard of conduct. Such determination shall be made, with respect to a Person who is a Director or officer at the time of such determination, (a) by a majority vote of the Directors who are not parties to such action, suit or proceeding, even with less than a quorum, or (b) if there are no such Directors, or if such Directors so direct, by independent legal counsel in a written opinion, or (c) by the NiSource Member and the BIP Investor Member. Such determination shall be made, with respect to former Directors and officers, by any Person or Persons having the authority to act on the matter on behalf of the Company.

Section 11.5 Reliance on Information. For purposes of any determination under Section 11.3, a present or former Director or officer of the Company shall be deemed to have acted in good faith and have otherwise met the applicable standard of conduct set forth in Section 11.3 if his or her action is based on the records or books of account of the Company or on information supplied to him or her by a Director or an officer of the Company in the course of his or her duties, or on the advice of legal counsel for the Company or on information or records given or reports made to the Company by an independent certified public accountant or by an appraiser or other expert selected with reasonable care by the Company. The provisions of this Section 11.5 shall not be deemed to be exclusive or to limit in any way the circumstances in which a present or former Director or officer of the Company may be deemed to have met the applicable standard of conduct set forth in Section 11.3.

Section 11.6 Advancement of Expenses. Expenses (including reasonable attorneys' fees) incurred by the present or former Director or officer of the Company in defending any civil, criminal, administrative or investigative action, suit or proceeding may be paid by the Company as authorized in the specific case in the same manner described in Section 11.4, upon receipt of a written affirmation of the present or former Director or officer that he or she has met the standard of conduct described in Section 11.3 and upon receipt of a written undertaking by or on behalf of him or her to repay such amount if it shall ultimately be determined that he or she did not meet the standard of conduct, and a determination is made that the facts then known to those making the determination shall not preclude indemnification under this Article XI.

Section 11.7 Non-Exclusive Provisions. The indemnification and advancement of expenses provided by, or granted pursuant to, this Article XI shall not be deemed exclusive of any other rights to which those seeking indemnification or advancement of expenses may be entitled. The Company hereby acknowledges that certain of its Directors and certain of its Members and the direct and indirect partners therein or owners thereof (the "Fund Indemnitees") may have rights to indemnification, advancement of expenses and/or insurance with respect to their service on the Board (collectively, the "Fund Indemnitors"). The Company hereby agrees: (a) that it is the indemnitor of first resort (i.e., its obligations to the Fund Indemnitees are primary and any obligation of the Fund Indemnitors to advance expenses or to provide indemnification for the same expenses or liabilities incurred by the Fund Indemnitees are secondary) and (b) that it irrevocably waives, relinquishes and releases the Fund Indemnitors from any and all claims against the Fund Indemnitors for contribution, subrogation or any other recovery of any kind in respect thereof, except to the extent that a Fund Indemnitee breaches its undertaking to repay advanced expenses as provided in Section 11.6. The Company further agrees that no advancement or payment by the Fund Indemnitors on behalf of the Fund Indemnitees with respect to any claim for which the Fund Indemnitees have sought indemnification from the Company shall affect the foregoing and that the Fund Indemnitors shall have a right of contribution and/or be subrogated to the extent of such advancement or payment to all of the rights of recovery of the Fund Indemnitees against the Company.

Section 11.8 Survival of Indemnification and Advancement of Expenses. The indemnification and advancement of expenses provided by, or granted pursuant to, this Article XI shall, unless otherwise provided when authorized or ratified, continue as to a Person who has ceased to be a Director or officer of the Company and shall inure to the benefit of his or her heirs, executors and administrators.

Section 11.9 Limitations. Notwithstanding anything contained in this Article XI to the contrary, the Company shall not be obligated to indemnify any Director or officer (or his or her heirs, executors or personal or legal representatives) or advance expenses in connection with a proceeding (or part thereof) initiated by such Person unless such proceeding (or part thereof) was authorized or consented to by the Board.

Article XII

REPRESENTATIONS AND WARRANTIES

Section 12.1 Company Representations and Warranties. As of the Effective Date, the Company hereby represents and warrants to the Members as follows:

(a) Each of the Company and GenCo is duly organized, validly existing and in good standing under the Laws of its jurisdiction of organization and has all requisite power and authority to own its properties and to carry on its business as now being conducted. Each of the Company and GenCo is duly qualified or licensed to conduct its business as currently conducted and is in good standing in each jurisdiction in which the location of the property owned, leased or operated by it or the nature of its business makes such qualification necessary.

(b) The Company has full legal capacity, power and authority to execute and deliver this Agreement and any other agreements or instruments executed by it in connection herewith and to perform its obligations herein and therein and to consummate the transactions contemplated herein and therein. The execution, delivery and performance of this Agreement by the Company, and the consummation of the transactions contemplated by this Agreement, have been duly authorized and approved by all necessary limited liability company action, and no other action on the part of the Company or its equityholders is necessary to authorize the execution, delivery and performance of this Agreement by the Company and the consummation of the transactions contemplated by this Agreement.

(c) This Agreement and the other agreements and instruments to be executed by the Company in connection herewith have been duly executed and delivered by the Company and are valid and binding obligations of the Company enforceable in accordance with their respective terms, except as enforcement thereof may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar Laws relating to or affecting enforcement of creditors' rights generally and except as enforcement thereof is subject to general principles of equity (regardless of whether enforcement is considered in a proceeding in equity or at law).

(d) The execution and delivery of this Agreement by the Company and the issuance of the Membership Interests contemplated herein will not (i) conflict with, or result in any violation of, or default, or give rise to any right of termination, cancellation or acceleration, (with or without notice or lapse of time, or both) under (x) the governing documents of the Company, (y) any Law or governmental order applicable to the Company or by which any property or asset of the Company is bound or affected or (z) any Contract or other obligation to which the Company is a party, (ii) require the Company to obtain any consent or approval, or give any notice to, or make any filing with, any Governmental Body on or prior to the Effective Date.

(e) The Membership Interests are duly authorized, validly issued, fully paid and, if applicable, nonassessable, and free and clear of all Liens, preemptive rights, rights of first refusal, subscription and similar rights (other than as described here and as arising under applicable securities Laws). The Membership Interests on Schedule 1 constitute all of the issued and outstanding Equity Interests of the Company as of the Effective Date.

(f) The Company does not have any liabilities other than (i) for Taxes accrued and not yet payable or being contested in good faith through appropriate proceedings so long as adequate reserves have been maintained in accordance with U.S. GAAP, (ii) for obligations pursuant to this Agreement, (iii) liabilities incurred in the ordinary course of business of the Company and its Subsidiaries as conducted prior to the Effective Date, including pursuant to Contracts with respect to the purchase, development, financing, construction, commercialization, ownership, operation or maintenance of the GenCo Assets in connection with the Company Business, and (iv) for obligations under its organizational documents and nominal amounts necessary for the corporate maintenance and existence of the Company.

(g) The Company has no Subsidiaries, other than GenCo, and does not own, directly or indirectly, any Equity Interests in, or any securities convertible into or exercisable or exchangeable for Equity Interests of, any other Person, nor is the Company a party to any agreement, option, warrant, right or other commitment obligating it to acquire any such Equity Interests.

(h) The Company owns one hundred percent (100%) of the membership interests in GenCo and such membership interests are duly authorized, validly issued, fully paid and, if applicable, nonassessable, and free and clear of all Liens, preemptive rights, rights of first refusal, subscription and similar rights (other than as described here and as arising under applicable securities Laws). Such membership interests constitute all of the issued and outstanding Equity Interests of GenCo as of the Effective Date.

Section 12.2 Members Representations and Warranties. As of the Effective Date, each Member hereby represents and warrants, severally and not jointly, to the Company and to the other Member as follows:

(a) Such Member is a limited liability company or limited partnership duly organized, validly existing and in good standing under the Laws of its jurisdiction of organization or formation, as applicable, with full power and authority to enter into this Agreement and perform all of its obligations hereunder.

(b) The execution and delivery of this Agreement by such Member, and the performance by such Member of its obligations hereunder, have been duly and validly authorized by all requisite action by such Member, and no other proceedings on the part of such Member are necessary to authorize the execution, delivery or performance of this Agreement by such Member.

(c) This Agreement has been duly and validly executed and delivered by such Member, and, assuming that this Agreement is a valid and binding obligation of the other Parties, this Agreement constitutes a valid and binding obligation of such Member, enforceable against such Member in accordance with its terms, except as limited by the application of bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other Laws relating to or affecting creditors' rights or general principles of equity.

(d) The execution and delivery by such Member of this Agreement, and the performance by such Member of its obligations hereunder, does not (i) violate or breach its Organizational Documents, (ii) violate any applicable Law to which such Member is subject or by which any of its assets are bound, or (iii) result in any breach of or constitute a default (or an event that, with notice or lapse of time or both, would become a default) under any Contract to which such Member is a party or by which any of its assets are bound.

(e) Such Member is acquiring its Membership Interests (i) for such Member's own account and not directly or indirectly for the account of any other Person and (ii) for investment and not with a view to their sale or distribution. Such Member understands that the Membership Interests have not been registered under the Securities Act and may be resold only if registered pursuant to the provisions of the Securities Act or if an exemption from registration is available. Such Member understands that no public market now exists for the Membership Interests and that it is unlikely that a public market will ever exist for the Membership Interests. Such Member understands that its investment in the Company is highly speculative in nature and is subject to a high degree of risk of loss, in whole or in part.

Article XIII MISCELLANEOUS

Section 13.1 Notices. Except as otherwise expressly provided herein, all notices, demands and other communications to be given or delivered under or by reason of the provisions of this Agreement shall be in writing and shall be deemed to have been given (a) when personally delivered, (b) when transmitted by electronic mail (unless if transmitted after 5:00 p.m. Eastern time or other than on a Business Day, then on the next Business Day) to the address specified below (with confirmation of transmission), (c) when sent by internationally-recognized courier in which case it shall be deemed to have been given at the time of actual recorded delivery, or (d) the third (3rd) Business Day following the day on which the same is sent by certified or registered mail, postage prepaid, in each case, to the respective Party at the number, electronic mail address or street address, as applicable, set forth below, or at such other number, electronic mail address or street address as such Party may specify by written notice to the other Party.

Notices to either Investor Member:

BIP Orion Holdco L.P or BIP Orion Holdco II L.P.,
345 Park Avenue
New York, NY 10154
Attention: Legal Counsel – Blackstone Infrastructure Partners; Max Wade
Email: BIP-Legal@blackstone.com; max.wade@blackstone.com

with copies to (which shall not constitute notice):

Paul, Weiss, Rifkind, Wharton & Garrison LLP
1285 Avenue of the Americas
New York, NY 10019
Attention: Ravi Purohit; Michael Spirtos
Email: rpurohit@paulweiss.com; mspirtos@paulweiss.com

Notices to the NiSource Member:

Generation Holdings I LLC
290 W. Nationwide Boulevard
Columbus, OH 43215
Attention: Shawn Anderson, Executive Vice President and Chief Financial Officer; Kim Cuccia, Senior Vice President, General Counsel and Corporate Secretary
Email: sanderson@nisource.com; kscuccia@nisource.com

with a copy to (which shall not constitute notice):

McGuireWoods LLP
800 East Canal Street
Richmond, Virginia 23219
Attention: Joanne Katsantonis; Emilie McNally
Email: jkatsantonis@mcguirewoods.com; emcnally@mcguirewoods.com

Notices to the Company:

Generation Holdings II LLC
290 W. Nationwide Boulevard
Columbus, OH 43215
Attention: Shawn Anderson, Executive Vice President and Chief Financial Officer; Kim Cuccia, Senior Vice President, General Counsel and Corporate Secretary
Email: sanderson@nisource.com; kscuccia@nisource.com

with a copy to (which shall not constitute notice):

McGuireWoods LLP
800 East Canal Street
Richmond, Virginia 23219
Attention: Joanne Katsantonis; Emilie McNally
Email: jkatsantonis@mcguirewoods.com; emcnally@mcguirewoods.com

Section 13.2 Assignment. This Agreement and all of the provisions hereof shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns; provided, that no Member, nor the Company, shall purport to assign or Transfer all or any of its rights or obligations under this Agreement nor grant, declare, create or dispose of any right or interest in this Agreement in whole or in part except with respect to a Transfer in accordance with the terms of this Agreement, and any attempted or purported assignment hereof not in accordance with the terms hereof shall be void ab initio.

Section 13.3 Waiver of Partition. Each Member hereby waives any right to partition of the Company property.

Section 13.4 Further Assurances. From and after the Effective Date, from time to time, as and when requested by any Party and at such Party's expense, any other Party shall execute and deliver, or

cause to be executed and delivered, all such documents and instruments and shall take, or cause to be taken, all such further or other actions as such requesting Party may reasonably deem necessary or desirable to carry out the purposes and intent of this Agreement.

Section 13.5 Third Party Beneficiaries. Except as otherwise expressly provided herein, nothing expressed or referred to in this Agreement shall be construed to give any Person other than the Parties any legal or equitable right, remedy or claim under or with respect to this Agreement or any provision of this Agreement; provided, that Covered Persons are express third party beneficiaries of Article XI.

Section 13.6 Parties in Interest; Non-Recourse. This Agreement shall inure to the benefit of, and be binding upon, the Parties and their respective successors, legal representatives and permitted assigns. This Agreement may only be enforced against, and any claim, action, suit, proceeding or investigation based upon, arising out of or related to this Agreement may only be brought against, the Persons that are expressly named as Parties to this Agreement. Except to the extent named as a Party to this Agreement, and then only to the extent of the specific obligations of such Parties set forth in this Agreement, no past, present or future shareholder, member, partner, manager, director, officer, employee, Affiliate (without giving effect to the proviso set forth in the definition thereof), agent or advisor of any Party shall have any liability (whether in contract, tort, equity or otherwise or by or through theories of equity, agency, control, instrumentality, alter ego, domination, sham, single business enterprise, piercing the veil, undercapitalization or any other attempt to avoid or disregard the entity form of any Person not a Party) for any of the representations, warranties, covenants, agreements or other obligations or liabilities of any of the Parties or for any claim, action, suit, proceeding or investigation based upon, arising out of or related to this Agreement. Notwithstanding anything contained herein, in no event shall this Section 13.6 limit in any way or waive any rights the Company or the NiSource Member may have with respect to the Equity Commitment Letter.

Section 13.7 Severability. If any term, provision, covenant or restriction contained in this Agreement is held by a court of competent jurisdiction or other authority to be invalid, void, unenforceable or against its regulatory policy, the remainder of the terms, provisions, covenants and restrictions contained in this Agreement shall remain in full force and effect and shall in no way be affected, impaired or invalidated, and, to the extent permitted and possible, any invalid, void or unenforceable term shall be deemed replaced by a term that is valid and enforceable and that comes closest to expressing the intention of such invalid, void or unenforceable term.

Section 13.8 Construction. The language used in this Agreement shall be deemed to be the language chosen by the Parties to express their mutual intent, and no rule of strict construction shall be applied against any Person. The headings of the sections and paragraphs of this Agreement have been inserted for convenience of reference only and shall in no way restrict or otherwise modify any of the terms or provisions hereof.

Section 13.9 Complete Agreement. This Agreement (including any schedules thereto), constitutes the entire agreement of the Parties hereto with respect to the subject matter hereof and thereof and supersedes any prior understandings, agreements or representations by or among the Parties hereto or Affiliates thereof, written or oral, to the extent they relate in any way to the subject matter hereof.

Section 13.10 Amendment; Waiver. Subject to Article VIII, neither this Agreement nor any other Organizational Document of the Company may be amended (whether by merger or otherwise) except in a written instrument signed by Members owning at least a majority of the Membership Interests; provided, that (a) the prior written consent of any Member shall be required in respect of any such proposed modification, alteration, supplement or amendment that would have a material disproportionate adverse impact on that Member (in its capacity as a Member) as compared to the other Members (in their capacity as Members) and (b) notwithstanding anything in this Agreement to the contrary, Article V, Article VI, Article VII, Article VIII and this Section 13.10 may not be amended other than by a written instrument signed by the BIP Investor Member. In the event that the Company issues Membership Interests to one (1) or more Third Parties pursuant to Section 5.1(c) or Section 7.1, the Members and the Company shall negotiate in good faith to amend this Agreement to the extent reasonably necessary to reflect such additional Members. Any amendment or revision to Schedule 1 that is made by an officer solely to reflect information regarding Members or the Transfer or issuance of Membership Interests made in accordance with the terms of this Agreement shall not be considered an amendment to this Agreement and shall not require any Board or Member approval. Any failure or delay on the part of any Party in exercising any power or right hereunder shall not operate as a waiver thereof, nor shall any single or partial exercise of any such right or power preclude any other or further exercise thereof or the exercise of any other right or power hereunder or otherwise available at law or in equity.

Section 13.11 Governing Law. This Agreement, and any claim, action, suit, investigation or proceeding of any kind whatsoever, including a counterclaim, cross-claim or defense, regardless of the legal theory under which such liability or obligation may be sought to be imposed, whether sounding in contract or tort, or whether at law or in equity, or otherwise under any legal or equitable theory, that may be based upon, arising out of or related to this Agreement or the negotiation, execution or performance of this Agreement or the transactions contemplated hereby shall be governed by and construed in accordance with the internal Laws of the State of Delaware applicable to agreements executed and performed entirely within such State without regards to conflicts of law principles of the State of Delaware or any other jurisdiction that would cause the Laws of any jurisdiction other than the State of Delaware to apply.

Section 13.12 Specific Performance. The Parties agree that irreparable damage, for which monetary relief, even if available, shall not be an adequate remedy, would occur in the event that any provision of this Agreement is not performed in accordance with its specific terms or is otherwise breached. It is accordingly agreed that (a) the Parties shall be entitled to seek an injunction or injunctions, specific performance or other equitable relief to prevent breaches of this Agreement and to enforce specifically the terms and provisions hereof without proof of damages or otherwise, this being in addition to any other remedy to which they are entitled under this Agreement, and (b) the right of specific performance and other equitable relief is an integral part of this Agreement and the business and legal understandings among the Members with respect to the Company, and without that right, none of the Members would have entered into this Agreement. The Parties acknowledge and agree that any Party pursuing an injunction or injunctions or other Order to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement in accordance with this Section 13.12 shall not be required to provide any bond or other security in connection with any such Order. The remedies available to the Parties pursuant to this Section 13.12 shall be in addition to any other remedy to which they may be entitled at law or in equity, and the election to pursue an injunction or specific performance shall not restrict, impair or otherwise limit any Party from seeking to collect or collecting damages. Each of the Parties agrees that it shall not oppose the granting of an injunction, specific performance and other equitable relief on the basis that any other Party has an adequate remedy at law or that any award of specific performance is not an appropriate remedy for any reason at law or in equity.

Section 13.13 Escalation; Arbitration.

(a) In connection with any dispute, controversy or claim among the Members relating to or arising out of this Agreement, the Members will use their reasonable efforts to resolve such dispute within thirty (30) days. If the dispute has not been resolved within such thirty (30) day period, the Members will escalate the dispute to the respective Senior Officers, who will meet to discuss and use their reasonable efforts to resolve the dispute. If the Members remain unable to resolve the dispute within thirty (30) days of the initial meeting of the Senior Officers or such later date as the Members subject to such dispute may agree, such dispute shall be finally settled by binding arbitration administered by the American Arbitration Association ("AAA") utilizing its Commercial Arbitration Rules in effect as of the date the arbitration is commenced. The arbitration shall be conducted before a single arbitrator, if the Parties can agree on the one arbitrator. If the Parties cannot agree on a single arbitrator, there shall be a panel of three arbitrators with one chosen by the BIP Investor Member, one chosen by the NiSource Member, and the third arbitrator selected by the two Members-appointed arbitrators. If a Party fails to appoint an arbitrator within 30 days following a written request by another Party to do so or if the two party-appointed arbitrators fail to agree upon the selection of a third arbitrator, as applicable, within thirty (30) days following their appointment, the additional arbitrator shall be selected by the AAA pursuant to its applicable procedures. Each arbitrator shall be disinterested and have at least twenty (20) years of experience with commercial matters. The arbitrator(s) shall have the power to award any appropriate remedy consistent with the objectives of the arbitration and subject to, and consistent with, all Laws and Orders applicable to the Company and its Subsidiaries (including, for the avoidance of doubt, the necessity of obtaining any requisite authorization, approval or consent of any Governmental Body necessary to implement the appropriate remedy). The decision of the one arbitrator or, if applicable, the majority of the three arbitrators shall be final and binding upon the Parties (subject only to limited review as required by applicable Law). Judgment upon the award of the arbitrator(s) may be entered in any court of competent jurisdiction or otherwise enforced in any jurisdiction in any manner provided by applicable Law. The losing Party shall pay the prevailing Party's attorney's fees and costs and the costs associated with the arbitration, including expert fees and costs and the arbitrators' fees and costs; provided, however, that each Party shall bear its own fees and costs until the arbitrator(s) determine which, if any, Party is the prevailing Party and the amount that is due to such prevailing Party. The arbitration proceedings shall take place in Chicago, Illinois and, for the avoidance of doubt, the arbitration proceedings shall be conducted in the English language.

(b) All discussions, negotiations and proceedings under this Section 13.13, and all evidence given or discovered pursuant hereto, will be maintained in strict confidence by all Parties, except where disclosure is required by applicable Law, necessary to comply with any legal requirements of such Party or necessary or advisable in order for a Party to assert any legal rights or remedies, including the filing of a complaint with a court or, based on the advice of counsel, such disclosure is determined to be necessary or advisable under applicable securities Laws or the rules of any stock exchange on which any of such Party's securities are traded. Disclosure of the existence of any arbitration or of any award rendered therein may be made as part of any action in court for interim or provisional relief or to confirm or enforce such award.

(c) Any settlement discussions occurring and negotiating positions taken by any Party in connection with the procedures under this Section 13.13 will be subject to Rule 408 of the Federal Rules of Civil Procedure and shall not be admissible as evidence in any proceeding relating to the subject matter of this Agreement.

(d) The fact that the dispute resolution procedure specified in this Section 13.13 has been or may be invoked will not excuse any Party from performing its obligations under this Agreement, and during the pendency of any such procedure, all Parties must continue to perform their respective obligations in good faith. In addition, in no event shall the fact that this provision has been invoked and the pendency of the proceedings limit, suspend, delay or waive any other rights and remedies provided in this Agreement to any Member.

(e) Notwithstanding the agreement to arbitrate contained in this Section 13.13, in the event that either Party wishes to seek a temporary restraining order, a preliminary or temporary injunction, or other injunctive relief in connection with any claim, demand, cause of action, dispute, controversy, or other matter arising out of or relating to this Agreement or the alleged breach thereof, whether such claim sounds in contract, tort, or otherwise, at law or in equity, under state or federal law, whether provided by statute or the common law, each Party shall have the right to pursue such injunctive relief in court, rather than by arbitration. The Parties agree that such action for a temporary restraining order, a preliminary or temporary injunction, or other injunctive relief may be brought in the state or federal courts of Delaware, or in any other forum in which jurisdiction is appropriate.

Section 13.14 Counterparts. This Agreement may be executed in counterparts, and any Party may execute any such counterpart, each of which when executed and delivered shall be deemed to be an original and all of which counterparts taken together shall constitute one and the same instrument. This Agreement shall become effective when each Party shall have received a counterpart hereof signed by the other Parties. The Parties agree that the delivery of this Agreement may be effected by means of an exchange of facsimile or electronically transmitted signatures.

Section 13.15 Fair Market Value Determination. In the event the Board makes a determination of Fair Market Value under this Agreement, upon request by the NiSource Member or the BIP Investor Member, so long as such Member holds a Percentage Interest (or, with respect to the BIP Investor Member, the Investor Members collectively hold an aggregate Percentage Interest) greater than five percent (5%), within five (5) Business Days after receiving written notice of the Board's determination in connection with any determination of Fair Market Value of Membership Interests or other assets under this Agreement (which determination shall be provided by the Company to each Member promptly following the making thereof), the Company shall select a nationally recognized independent valuation firm with no existing or prior business or personal relationship with any Member or any of its Affiliates in the three year period immediately preceding the date of engagement, pursuant to this Section 13.15 (the "Independent Evaluator") to determine such Fair Market Value. Each of the Company and the requesting Member shall submit their view of the Fair Market Value of the Membership Interests or the relevant asset(s) to the Independent Evaluator, and each party will receive copies of all information provided to the Independent Evaluator by the other party. The final Independent Evaluator's determination of the Fair Market Value of such Membership Interests or asset(s) shall be set forth in a detailed written report addressed to the Company and the Members within thirty (30) days following the Company's selection of such Independent Evaluator and such determination shall be final, conclusive and binding. In rendering its decision, the Independent Evaluator shall determine which of the positions of the Company and the requesting Member submitted to the Independent Evaluator is, in the aggregate, more accurate (which report shall include a worksheet setting forth the material calculations used in arriving at such

determination), and, based on such determination, adopt either the Fair Market Value determined by the Company or the requesting Member. Any fees and expenses of the Independent Evaluator incurred in resolving the disputed matter(s) will be borne by the party whose positions were not adopted by the Independent Evaluator. Notwithstanding the foregoing, the Board's determination of Fair Market Value under this Agreement shall be conclusive and relied upon by the Members in carrying out their obligations hereunder, unless and until the Independent Evaluator determines otherwise. The pendency of this process shall not excuse the performance of any obligations of a Member hereunder.

Section 13.16 Certain Definitions. As used in this Agreement, the following terms shall have the meanings ascribed to them below:

“Act” means the Delaware Limited Liability Company Act, as amended from time to time.

“Adjusted Capital Account” means, with respect to any Member, the balance in such Member's Capital Account as of the end of the relevant Allocation Year or other period, after giving effect to the following adjustments:

(a) Add to such Capital Account the following items:

(i) The amount, if any, that such Member is obligated to contribute to the Company upon liquidation of such Member's Percentage Interest; and

(ii) The amount that such Member is obligated to restore or is deemed to be obligated to restore pursuant to Treasury Regulations Section 1.704-1(b)(2)(ii)(c) or the penultimate sentence of each of Treasury Regulations Sections 1.704-2(g)(1) and 1.704-2(i)(5).

(b) Subtract from such Capital Account such Member's share of the items described in Treasury Regulations Sections 1.704-1(b)(2)(ii)(d)(4), 1.704-1(b)(2)(ii)(d)(5) and 1.704-1(b)(2)(ii)(d)(6).

The foregoing definition of Adjusted Capital Account is intended to comply with the provisions of Treasury Regulations Section 1.704-1(b)(2)(ii)(d) and shall be interpreted consistently therewith.

“Adjusted Capital Account Deficit” means, with respect to any Member, the deficit balance, if any, in such Member's Adjusted Capital Account as of the end of the Allocation Year (or other relevant period).

“Advisors” means, with respect to any Person, the accountants, attorneys, consultants, advisors, investment bankers, or other representatives of such Person.

“Affiliate” of any particular Person means any other Person Controlling, Controlled by or under common Control with such particular Person, provided, however, that, (i) no portfolio company of any investment fund affiliated with or advised by The Blackstone Group Inc. or Blackstone Infrastructure Partners L.P., or Blackstone Infrastructure Advisors, LLC, shall be deemed to be an “Affiliate” of either Investor Member (excluding the Investor Members' Subsidiaries) and (ii) no investment fund affiliated with or advised by The Blackstone Group Inc. shall be deemed an “Affiliate” of either Investor Member (excluding funds or investment vehicles controlled or advised by Blackstone Infrastructure Advisors, LLC).

“Affiliated Member” means a Member that is Controlled by a NHII Member, Controls a NHII Member, or is under common Control with a NHII Member.

“Affiliated NHII Member” means a NHII Member that is Controlled by a Member, Controls a Member, or is under common Control with a Member.

“Allocation Year” means (a) the period commencing on the Effective Date and ending on the immediately succeeding December 31; (b) any subsequent twelve (12) month period commencing on January 1 and ending on December 31; or (c) any portion of the period described in preceding clause (a) or (b) for which the Company is required to allocate items of the Company income, gain, loss, deduction or credit.

“Anti-Corruption Laws” means any Law concerning or relating to bribery or corruption imposed, administered or enforced by any Governmental Body.

“Anti-Money Laundering Laws” means any Law concerning or relating to money laundering, any predicate crime to money laundering or any record keeping, disclosure or reporting requirements related to money laundering imposed, administered or enforced by any Governmental Body.

“Assumed Tax Liability” means, for any Member, the product of (a) such Member’s allocable share of net taxable income of the Company for such Fiscal Year (or applicable portion thereof), reduced by such Member’s allocable share of cumulative net taxable loss of the Company not previously been taken into account (calculated taking into account the effect of any basis adjustment under Code Section 734, 743 or 754 and allocations pursuant to Code Section 704(c)), determined as if such Member has no items of income, gain, loss, deduction or credit other than through the Company, multiplied by (b) the Assumed Tax Rate.

“Assumed Tax Rate” means the highest effective combined marginal U.S. federal, state and local income tax rate applicable to a corporation for such Fiscal Year (taking into account the character of the underlying taxable income) and the deductibility of state and local income taxes for U.S. federal income tax purposes (and any applicable limitations thereon). The Assumed Tax Rate shall be the same for each Member.

“Available Cash” means, for any fiscal quarter, the cash flow generated from the normal business operations of the Company and its Subsidiaries in such fiscal quarter, less any amounts that the Board reasonably determines are necessary and appropriate to be retained in order to (a) permit the Company and its Subsidiaries to pay their obligations as they become due in the ordinary course of business, (b) maintain the Company’s and its Subsidiaries’ capital structure and credit metrics, (c) subject to Section 8.1(1), fund planned and approved (as applicable) capital expenditures, (d) maintain an adequate level of working capital, (e) maintain prudent reserves for future obligations (including contingent obligations of the Company and its Subsidiaries), (f) comply with applicable Law, Order, the terms of the Company’s and its Subsidiaries’ Indebtedness (including making any required payments of principal or interest in satisfaction of Indebtedness), or (g) respond to an Emergency Situation.

“Business Day” means any day other than a Saturday, Sunday or a day on which banking institutions located in New York, New York or Delaware are closed generally.

“Capital Account” means the capital account maintained for each Member on the Company’s books and records in accordance with the following provisions:

(a) To each Member’s Capital Account there shall be added (i) such Member’s Capital Contributions, (ii) such Member’s allocable share of net Profits and any items in the nature of income or gain that are specially allocated to such Member pursuant to Section 5.6 or Section 5.7 hereof or other provisions of this Agreement, and (iii) the amount of any Company liabilities assumed by such Member or which are secured by any property distributed to such Member.

(b) From each Member's Capital Account there shall be subtracted (i) the amount of (A) cash and (B) the Gross Asset Value of any Company assets (other than cash) distributed to such Member pursuant to any provision of this Agreement, (ii) such Member's allocable share of net Losses and any other items in the nature of expenses or losses that are specially allocated to such Member pursuant to Section 5.6 or Section 5.7 hereof or other provisions of this Agreement, and (iii) liabilities of such Member assumed by the Company or which are secured by any property contributed by such Member to the Company.

(c) In the event any Membership Interest is transferred in accordance with the terms of this Agreement, the transferee shall succeed to the Capital Account of the transferor to the extent it relates to the transferred Membership Interest.

(d) In determining the amount of any liability for purposes of subparagraphs (a) and (b) above, there shall be taken into account Code Section 752(c) and any other applicable provisions of the Code and Regulations.

The foregoing provisions and the other provisions of this Agreement relating to the maintenance of Capital Accounts are intended to comply with Regulations Sections 1.704-1(b) and 1.704-2 and shall be interpreted and applied in a manner consistent with such Regulations.

"Capital Contribution" means, with respect to any Member, the total amount of cash and the initial Gross Asset Value of property (other than cash) contributed to the capital of the Company by such Member, whether as an initial Capital Contribution or as an additional Capital Contribution.

"Change in Control" means with respect to the applicable Party, any person or group (within the meaning of Sections 13(d)(3) and 14(d)(2) of the Securities Exchange Act of 1934, as amended) at any time becoming the beneficial owner of more than fifty percent (50%) of the combined voting power of the voting securities of such Party (including through general partner and limited partner arrangements).

"Code" means the Internal Revenue Code of 1986, as amended.

"Company Group" means the Company and each of its Subsidiaries, collectively.

"Company Minimum Gain" has the meaning set forth in Treasury Regulations Sections 1.704-2(b)(2) and 1.704-2(d)(1) for the phrase "partnership minimum gain."

"Competitor" means any Person that is, or through its Subsidiaries is, directly involved in or competes with the Company Business in the United States. For the avoidance of doubt, a Competitor shall not include any financial sponsors that own equity in any Person that is directly involved in the Company Business in the United States.

"Consolidated Capitalization" means the sum of the Consolidated Debt and all amounts that would, in conformity with GAAP, be included on a consolidated balance sheet of the Company and its Subsidiaries under the total members' equity interests at such time.

"Consolidated Debt" means, the Indebtedness of the Company and its Subsidiaries that would be classified as debt on a consolidated balance sheet of the Company and its Subsidiaries in accordance with GAAP.

“Contract” means any written agreement, arrangement, commitment, indenture, instrument, purchase order, license or other binding agreement.

“Control” means the possession, directly or indirectly, of the power to direct the management and policies of a Person whether through the ownership of voting securities, Contract or otherwise.

“Covered Person” means any (a) Member, any Affiliate of a Member or any officers, directors, shareholders, partners, members, employees, representatives or agents of a Member or their respective direct or indirect Affiliates, (b) Director, or (c) employee, officer, or agent of the Company or its Affiliates.

“CPI Escalator” means that certain increase calculated annually on the anniversary of the Effective Date by the percentage increase of services measured by the consumer price index as determined by the U.S. Department of Labor, Bureau of Labor Statistics.

“Debt Financing” means any debt financing incurred by the BIP Investor Member or any of its Affiliates (other than the Company), including, the incurrence of any loans or the issuance of any bonds, notes, debentures or hybrid securities.

“Debt-to-Capital Ratio” means the ratio of the Consolidated Debt to Consolidated Capitalization.

“Depreciation” means, for Allocation Year or other period, an amount equal to the depreciation, amortization or other cost recovery deduction allowable for federal income tax purposes with respect to an asset for such Allocation Year or other period, except that (a) with respect to an asset the Gross Asset Value of which differs from its adjusted basis for U.S. federal income tax purposes and which difference is being eliminated by use of the “remedial allocation method” as defined in Treasury Regulations Section 1.704-3(d), Depreciation for such period shall be the amount of the book basis recovered for such period under the rules prescribed in Treasury Regulations Section 1.704-3(d)(2), and (b) if the Gross Asset Value of an asset differs from its adjusted basis for federal income tax purposes at the beginning of such Allocation Year or other period, Depreciation shall be an amount that bears the same ratio to such beginning Gross Asset Value as the federal income tax depreciation, amortization or other cost recovery deduction for such Allocation Year or other period bears to such beginning adjusted tax basis; provided, however, that if the federal income tax depreciation, amortization or other cost recovery deduction for such Allocation Year or other period is zero, Depreciation shall be determined with reference to such beginning Gross Asset Value using any reasonable method selected by the Board.

“EBITDA” means earnings before interest, taxes, depreciation and amortization, calculated consistently with the methodology set forth in the Seller Model.

“Emergency Expenditure” means amounts required to be incurred in order to respond to an Emergency Situation or to avoid an Emergency Situation in a manner that is consistent with general practices applicable to facilities used in the Company Business or consistent with the past operations of the Company or its Affiliates (including NIPSCO), but only to the extent such expenditures are reasonably designed to ameliorate the consequences, or an immediate threat of any of the consequences, of the issues set forth in the definition of “Emergency Situation”.

“Emergency Situation” means, with respect to the business of the Company and its Subsidiaries, any abnormal system condition or abnormal situation requiring immediate action to maintain the system, frequency, loading within acceptable limits or voltage or to prevent loss of firm load; material equipment damage or tripping of system elements that would reasonably be expected to materially and adversely

affect reliability of an electric system or any other occurrence or condition that requires immediate action to prevent or mitigate an immediate and material threat to the safety of Persons or the operational integrity of the assets and business of the Company or its Subsidiaries; or any other condition or occurrence requiring prompt implementation of emergency procedures as defined by the applicable transmission grid operator, distribution or transmitting utility.

“Encumber” means to place a Lien against.

“Equity Commitment Letter” means the Equity Commitment Letter dated as of the Effective Date by Blackstone Infrastructure Partners L.P. for the benefit of the Company in the amount equal to \$1,325,000,000.00 (the “Maximum Investor Commitment”).

“Equity Interests” means, with respect to any Person that is not a natural person, (i) capital stock, ordinary shares, partnership, limited liability company or membership interests or units (whether general or limited) or any other equity interests of such Person; (ii) subscriptions, calls, warrants, Contracts, options, commitments or rights entitling any Person to acquire, any interests referred to in clause (i); (iii) securities or instruments convertible into or exercisable or exchangeable for any interests referred to in clause (i) and (iv) stock or unit appreciation rights, liquidation rights, contingent value rights, restricted stock units, or phantom equity or that confers on a Person the right to receive any type of interest referred to in clauses (i) through (iii).

“Exchange Act” has the meaning set forth in the definition of “Excluded Membership Interests”.

“Excluded Membership Interests” means any Membership Interests or other Equity Interests in the Company issued in connection with:

- (a) any issuance to a Third Party pursuant to and in accordance with Section 7.1;
- (b) any arrangement approved unanimously by the Board for the return of income or capital to the Members;
- (c) any equity split, equity dividend or any similar recapitalization; or
- (d) the commencement of any offering or registration of Membership Interests or other Equity Interests of the Company or any of its Subsidiaries, pursuant to a registration statement filed in accordance with the United States Securities Act of 1933 (the “Securities Act”) or under the Securities and Exchange Act of 1934 (the “Exchange Act”).

“Excluded Transactions” means Transactions in the ordinary course of the Company Business, and, in each case, on an arms-length basis with respect to (i) the sale and transfer of Zonal Resource Credits or other similar capacity credits to or from NIPSCO or its Subsidiaries to or from the Company or its Subsidiaries, (ii) pilot programs, and (iii) similar undertakings by the Company or its Subsidiaries in connection with the Company Business, provided, however, the Members shall discuss in good faith any necessary adjustments to this definition on or after the date that is ten (10) years from the Effective Date, provided, further that any adjustments to this definition shall be mutually agreed by the Members.

“Fair Market Value” means, with respect to any asset (including Equity Interest), the price at which the asset would change hands between a willing buyer and a willing seller that are not affiliated parties, neither being under any compulsion to buy or to sell, and both having knowledge of the relevant facts and taking into account the full useful life of the asset. In valuing Membership Interests, no

consideration of any control, liquidity or minority discount or premium shall be taken into account. Fair Market Value shall be determined by the Board in accordance with the foregoing, subject to Section 13.15.

“FERC” means the U.S. Federal Energy Regulatory Commission or any successor agency thereto.

“GAAP” means United States generally accepted accounting principles applied on a consistent basis during the periods involved.

“GenCo Assets” means any and all current or future assets, rights, and properties (including any Subsidiaries) of the Company and Subsidiaries.

“GenCo Declination” means that certain order of the IURC approved on September 24, 2025, of the verified petition of GenCo for certain determinations by the IURC with respect to its jurisdiction over petitioner’s activities as a non-retail generator of electric power.

“GenCo Offtake Agreement” means any offtake agreements (including capacity supply agreements) pursuant to which the Company or its Subsidiaries will sell power, storage, capacity or ancillary products to NIPSCO to allow NIPSCO to fulfill its obligations to certain large load or hyperscale customers for each pursuant to a “special contract” or similar arrangement (including any tariff) as submitted to the IURC and/or otherwise consistent with applicable Law at such time, including any applicable IURC rules and regulations.

“Governmental Body” means any national, foreign, federal, regional, state, local, municipal or other governmental authority of any nature (including any division, department, agency, commission or other regulatory body thereof) and any court or arbitral tribunal, including any governmental, quasi-governmental or non-governmental body administering, regulating or having general oversight over electricity, power or the transmission or transportation thereof, including any regional transmission operator, independent system operator and any market monitor thereof.

“Gross Asset Value” means, with respect to any asset, the asset’s adjusted basis for federal income tax purposes, except as follows:

(a) The initial Gross Asset Value of any asset contributed by a Member to the Company shall be the gross fair market value of such asset on the date of the contribution, as determined by the Board, provided that the initial Gross Asset Values of the assets contributed to the Company pursuant to Section 5.1 shall be as set forth on Schedule 1.

(b) The Gross Asset Values of all Company assets immediately prior to the occurrence of any event described in subparagraphs (i) through (v) below shall be adjusted to equal their respective gross fair market values, as determined by the Board, as of the following times: The Gross Asset Values of all Company assets shall be adjusted to equal their respective gross fair market values, as determined by the Board, as of the following times: (i) the acquisition of an additional interest in the Company by any new or existing Member in exchange for more than a de minimis Capital Contribution; (ii) the distribution by the Company to a Member of more than a de minimis amount of property as consideration for an interest in the Company; (iii) the liquidation of the Company within the meaning of Treasury Regulations Section 1.704-1(b)(2)(ii)(g); (iv) in connection with the grant of an interest in the Company (other than a de minimis interest) as consideration for the provision of services to or for the benefit of the Company by an existing Member acting in a partner capacity, or by a new Member acting in a partner capacity in

anticipation of being a Member; and (v) the acquisition of an interest in the Company upon the exercise of a non-compensatory option in accordance with Treasury Regulations Section 1.704-1(b)(2)(iv)(s); provided, however, adjustments pursuant to clause (i), clause (ii), and clause (iv) above shall be made only if the Board reasonably determines that such adjustments are necessary or appropriate to reflect the relative economic interests of the Members in the Company; and provided further, if any non-compensatory option is outstanding, Gross Asset Values shall be adjusted in accordance with Treasury Regulation Sections 1.704-1(b)(2)(iv)(f)(1) and 1.704-1(b)(2)(iv)(h)(2);

(c) The Gross Asset Value of any Company asset distributed to a Member shall be the gross fair market value of such asset on the date of distribution as determined by the Board;

(d) The Gross Asset Values of Company assets shall be increased (or decreased) to reflect any adjustments to the adjusted basis of such assets pursuant to Code Section 734(b) or Code Section 743(b), but only to the extent that such adjustments are taken into account in determining Capital Accounts pursuant to Regulations Section 1.704-1(b)(2)(iv)(m); provided, however, that Gross Asset Values shall not be adjusted pursuant to this subparagraph (d) to the extent that an adjustment pursuant to subparagraph (b) above is made in connection with a transaction that would otherwise result in an adjustment pursuant to this subparagraph (d).

(e) If the Gross Asset Value of a Company asset has been determined or adjusted pursuant to subparagraph (a), subparagraph (b) or subparagraph (d) above, such Gross Asset Value shall thereafter be adjusted by the Depreciation taken into account with respect to such Company asset for purposes of computing net Profits and net Losses.

“Indebtedness” means indebtedness or debt as those terms are calculated in accordance with GAAP.

“Investor Call Trigger” means (i) either Investor Member fails to fund all or any portion of its share of a Mandatory Capital Contribution or any Additional Funding Requirement (other than a Mandatory Capital Contribution) in respect of two (2) events if either Investor Member indicated it would do so in its Response to Capital Call but failed to do so within the time period specified in Section 5.1; provided, that the NiSource Member shall be required to provide notice to the BIP Investor Member immediately upon any Investor Member’s first event of failure to fund that would trigger this right, (ii) the Investor Members’ aggregate Percentage Interest is equal to or less than five percent (5%), or (iii) the NiSource Member elects to pursue a spin off, split off or similar transaction of the Company, GenCo or an Affiliate; provided, in the case of this clause (iii), the NiSource Member may not exercise its Call Right unless the Spin Return Threshold would be satisfied in the event such contemplated transaction is consummated.

“Investor Consent Threshold” means a Percentage Interest equal to or greater than 19.9%; provided, that, solely in the event the Investor Members’ aggregate Percentage Interest is reduced in connection with issuances of Membership Interests in compliance with Sections 5.1 or 7.1, such reference to “19.9%” shall be replaced by “17.5%”.

“IRR” means, at any time of determination, the actual annual rate of return of the Investor Members (specified as a percentage) taking into account only the following, on a cash-in, cash-out basis: (a) all capital contributions actually made to the Company by or on behalf of the Investor Members or any of its Permitted Transferees with respect to their Membership Interests on or before such date, and (b) all cash distributions made to the Investor Members or any of their respective Permitted Transferees on or

before such date. For the avoidance of doubt, the IRR calculation would not include any tax payments at the Investor Members level. The IRR will be calculated using the XIRR function in the most recent version of Microsoft Excel (or if such program is no longer available, such other software program for calculating the IRR as is reasonably determined by the Board), and will be based on the actual dates of funding of such capital contributions and the actual dates of receipt of such cash distributions and proceeds.

“IURC” means the Indiana Utility Regulatory Commission.

“Law” means any law (statutory, common or otherwise), rule, regulation, code or ordinance enacted, adopted, promulgated or applied by any Governmental Body, including all regulatory requirements emanating from state and federal regulators of the Company Group’s businesses and operations.

“Liens” means all liens, encumbrances, mortgages, deeds of trust, pledges, security interests, charges, claims, proxy, voting trust or transfer restrictions, under any stockholder or similar agreement or Organizational Document.

“Maximum Investor Commitment” has the meaning set forth in the definition of “Equity Commitment Letter”.

“Member” means each of the NiSource Member and the Investor Members, and any Person admitted as an additional member of the Company or a substitute member of the Company pursuant to the provisions of this Agreement, each in its capacity as a member of the Company.

“Member Nonrecourse Debt” has the meaning of “partner nonrecourse debt” as set forth in Treasury Regulations Section 1.704-2(b)(4).

“Member Nonrecourse Debt Minimum Gain” means an amount, with respect to each Member Nonrecourse Debt, equal to the Company Minimum Gain that would result if such Member Nonrecourse Debt were treated as a Nonrecourse Liability, determined in accordance with Treasury Regulation Section 1.704-2(i)(3).

“Member Nonrecourse Deductions” has the meaning of “partner nonrecourse deductions” set forth in Treasury Regulations Section 1.704-2(i)(1) and 1.704-2(i)(2).

“Membership Interests” means membership interests of the Company.

“MOIC” means, as of any measurement time, with respect to any holder of Membership Interests, the number resulting from the quotient of (i) the cumulative amount of distributions received by such holder (or its predecessors in interest) in respect of such Membership Interests divided by (ii) the cumulative amount of all capital contributions made to the Company by such holder (or its predecessors in interest) in respect of such Membership Interests prior to such time; provided, that, for the purpose of foregoing calculation, the Investor Members shall be aggregated and treated as a single holder.

“New Securities” means any Membership Interests or other Equity Interests in the Company, other than any Excluded Membership Interests.

“NHII Member” means each Member as defined in the NHII Operating Agreement.

“NHII Operating Agreement” means that certain Third Amended and Restated Limited Liability Company Agreement dated as of the date hereof by and among NHII, NIPSCO Holdings I LLC, an Indiana limited liability company, BIP Blue Buyer L.L.C., a Delaware limited liability company, BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company, and solely for the purposes of Article VI thereto, the Parent.

“NIPSCO” means Northern Indiana Public Service Company LLC, an Indiana limited liability company.

“NiSource Leadership Team” means any individual serving as an officer at any Company Group.

“Nonrecourse Deductions” has the meaning set forth in Treasury Regulations Sections 1.704-2(b)(1) and 1.704-2(c).

“Nonrecourse Liability” has the meaning set forth in Treasury Regulations Sections 1.704-2(b)(3) and 1.752-1(a)(2).

“OFAC” means the U.S. Office of Foreign Assets Control.

“Order” means any order, ruling, decision, verdict, decree, writ, award, judgment, injunction, or other similar determination or finding of any Governmental Body.

“Organizational Documents” means, with respect to any corporation, its articles or certificate of incorporation, memorandum or articles of association and by-laws or documents of similar substance; with respect to any limited liability company, its articles of association, articles of organization or certificate of organization, formation or association and its operating agreement or limited liability company agreement or documents of similar substance; with respect to any limited partnership, its certificate of limited partnership and partnership agreement or documents of similar substance; and with respect to any other entity, documents of similar substance to any of the foregoing.

“Outside Group” means the Parent and its Subsidiaries, other than the Company and its Subsidiaries.

“Partnership Audit Rules” means Sections 6221 through 6241 of the Code, as enacted in Public Law 114-74, as may be amended, including any final or temporary Regulations, other administrative guidance or case law interpreting Sections 6221 through 6241 of the Code (and any analogous provision of state or local tax law).

“Partnership Representative” means, with respect to any Allocation Year, the Person designated for such year as the partnership representative for the Company pursuant to section 6223(a) of the Code or with respect to the tax law of any state or foreign jurisdiction, as a representative pursuant to a provision of law of such state or foreign jurisdiction corresponding to Section 6223(a) of the Code and shall also include the Person through whom a Partnership Representative acts.

“Percentage Interest” means, in respect of any Member, their relative ownership in the Membership Interests, expressed as a percentage, which shall be deemed to be equal to the number of Membership Interests that such Member owns divided by the total number of Membership Interests then outstanding.

“Permitted Transferee” means, with respect to the NiSource Member or either Investor Member, (a) a directly or indirectly wholly owned Subsidiary of such Member, (b) an Affiliate of such Member of which such Member is, directly or indirectly, a wholly owned Subsidiary (an “Affiliate Parent”), or (c) an Affiliate of such Member that is a wholly owned Subsidiary of an Affiliate Parent.

“Person(s)” means an individual, a partnership, a corporation, a limited liability company, an association, a joint stock company, a trust, a joint venture, an unincorporated organization or a Governmental Body.

“Preemptive Right Share” means a ratio of (a) the number of Membership Interests held by such Member with Preemptive Rights, to (b) the total number of Membership Interests then outstanding immediately prior to the issuance of New Securities giving rise to the Preemptive Rights.

“President” means the President of GenCo.

“Profits” and “Losses” mean, for each Allocation Year, an amount equal to the Company’s taxable income or loss for such Allocation Year, determined in accordance with Code Section 703(a) (for this purpose, all items of income, gain, loss, or deduction required to be stated separately pursuant to Code Section 703(a)(1) shall be included in taxable income or loss), with the following adjustments (without duplication):

(a) Any income of the Company that is exempt from federal income tax and not otherwise taken into account in computing Profits or Losses pursuant to this definition of “Profits” and “Losses” shall be added to such taxable income or loss;

(b) Any expenditures of the Company described in Code Section 705(a)(2)(B) or treated as Code Section 705(a)(2)(B) expenditures pursuant to Treasury Regulations Section 1.704-1(b)(2)(iv)(i), and not otherwise taken into account in computing Profits or Losses pursuant to this definition of “Profits” and “Losses,” shall be subtracted from such taxable income or loss;

(c) In the event the Gross Asset Value of any Company asset is adjusted pursuant to clause (b) or clause (c) of the definition of “Gross Asset Value,” the amount of such adjustment shall be treated as an item of gain (if the adjustment increases the Gross Asset Value of the asset) or an item of loss (if the adjustment decreases the Gross Asset Value of the asset) from the disposition of such asset and shall be taken into account for purposes of computing Profits or Losses;

(d) In lieu of the depreciation, amortization, and other cost recovery deductions taken into account in computing such taxable income or loss, there shall be taken into account Depreciation for such Allocation Year, computed in accordance with the definition of Depreciation;

(e) Gain or loss resulting from any disposition of property with respect to which gain or loss is recognized for federal income tax purposes shall be computed by reference to the Gross Asset Value of the property disposed of, notwithstanding that the adjusted tax basis of such property differs from its Gross Asset Value;

(f) To the extent an adjustment to the adjusted tax basis of any Company asset pursuant to Code Section 734(b) or Section 743(b) is required, pursuant to Treasury Regulations Section 1.704-1(b)(2)(iv)(m)(4), to be taken into account in determining Capital Accounts as a result of a distribution other than in liquidation of a Member’s interest in the Company, the amount of such adjustment shall be treated as an item of gain (if the adjustment increases the basis of the asset) or loss (if

the adjustment decreases such basis) from the disposition of such asset and shall be taken into account for purposes of computing Profits or Losses; and

(g) Notwithstanding any other provision of this definition, any items that are specially allocated pursuant to Section 5.7 or Section 5.8 shall not be taken into account in computing Profits or Losses.

The amounts of the items of Company income, gain, loss, or deduction available to be specially allocated pursuant to Section 5.7 and Section 5.8 shall be determined by applying rules analogous to those set forth in clause (a) through clause (f) of this definition.

“Prohibited Competitor” means (i) any Competitor listed on Appendix (A) hereto, as may be updated from time to time in accordance with Section 6.3(b) and (ii) any person owned or controlled by an entity existing under the laws of a country or territory that is subject to, or a target of, any Sanctions.

“Qualified Designee” means (i) with respect to NiSource Member, an employee of Parent or its Affiliates that is an officer of any such entity and (ii) with respect to BIP Investor Member, an employee of the BIP Investor Member or its parent company that is an officer or comparable position of such entity or is otherwise affiliated with such entity; provided, that a “Qualified Designee” shall not include any Person so long as such Person is (a) a director, officer, employee, or other Person affiliated with a Prohibited Competitor or (b) any Person convicted by a court or equivalent tribunal of any felony (or equivalent crime in the applicable jurisdiction) or of any misdemeanor (or equivalent crime in the applicable jurisdiction) that involves financial dishonesty or moral turpitude, or (c) any Person that would create a material reputational risk to the Company based on a good faith determination by the Board.

“Qualified Transferee” means any Person so long as such Person is (i) an asset manager with “assets under management” (as such term is commonly defined in the private equity industry) of at least \$5,000,000,000, (ii) a Person with its Equity Interests listed on a nationally recognized stock exchange which has a market capitalization of at least \$5,000,000,000 or (iii) a Person that based on its most recent audited balance sheet has at least \$5,000,000,000 of assets, and/or in all cases, is in the good faith determination of the Board of being financially capable of carrying out the obligations and promptly paying all liabilities as they become due and payable under and in accordance with this Agreement and such Person is not a Prohibited Competitor; provided, that a Person that consummated a foreclosure pursuant to Section 6.2(b) shall be deemed a Qualified Transferee.

“Qualifying Core Asset Base” means an amount equal to the net property, plant and equipment of the Qualifying Core Assets, taken as a whole, including any joint ventures consolidated on the Company’s financial statements, as determined based on the annual financial statements prepared according to GAAP.

“Qualifying Core Assets” means assets (including the GenCo Assets) utilized in connection with the conduct of the Company’s and its Subsidiaries’ business (a) on which the Company reasonably expects that it or its Subsidiaries will be eligible to include in the applicable rate base and to earn a return on through rates approved by the IURC, FERC or such other applicable Governmental Body that are commercially reasonable (to be determined by the Board in good faith) and are not otherwise inconsistent with such applicable Governmental Body (as the case may be) rate precedent or (b) which are reasonably necessary, including any generating facilities and related infrastructure, (as determined by the Board in good faith) for the Company’s and its Subsidiaries’ performance under the GenCo Offtake Agreements in accordance with the terms thereof or to serve certain large load or hyperscale customers pursuant to a

“special contract” or similar arrangement (including any tariff), as submitted to the IURC and/or otherwise consistent with applicable Law at such time, including any applicable IURC rules and regulations. For the avoidance of doubt, “Qualifying Core Assets” shall also include necessary or ancillary expenses to support such assets (including working capital). Further, for the avoidance of doubt, the sale of any excess electricity, storage, capacity or ancillary products generated or produced by any such generating facilities or related infrastructure within the applicable wholesale market shall not affect whether such assets, generating facilities or related infrastructure are Qualifying Core Assets.

“Representatives” means the directors, officers, employees, agents and Advisors of a Party.

“Sanctioned Country” means a country or territory that is the target of comprehensive Sanctions (currently, Cuba, Iran, North Korea, Syria, the Crimea region of Ukraine, and the so-called Donetsk and Luhansk People’s Republics in eastern Ukraine).

“Sanctioned Person” means, (a) any Person listed in any Sanctions-related list of designated Persons maintained by a Governmental Body described in the definition of “Sanctions,” (b) any Person operating, organized, domiciled or resident in a Sanctioned Country, (c) the government of, or a Governmental Body or government official of, any Sanctioned Country or of Venezuela, or (d) any Person directly or indirectly owned or otherwise controlled by, acting for or on behalf of, or acting at the direction of, any such Person described in clauses (a), (b), or (c).

“Sanctions” means any trade or economic sanctions imposed, administered or enforced from time to time by OFAC, the U.S. Department of State, His Majesty’s Treasury, the United Nations, the European Union or any agency or subdivision of any of the foregoing, including any regulations, rules and executive orders issued in connection therewith.

“Securities Act” has the meaning set forth in the definition of “Excluded Membership Interests”.

“Senior Officers” means with respect to the NiSource Member, the Chief Executive Officer of the Parent, and with respect to the Investor Members, the Global Head of Infrastructure of Blackstone Inc.

“Spin Return Threshold” means the Investor Return Threshold and the MOIC Return Threshold.

“Subsidiary” means, with respect to any Person, any entity of which a majority of the total voting power of shares of stock entitled (without regard to the occurrence of any contingency) to vote in the election of directors, managers or trustees thereof is at the time owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of such Person or a combination thereof or any partnership, association or other entity of which a majority of the partnership or other similar ownership interest is at the time owned or controlled, directly or indirectly, by such Person or one or more Subsidiaries of such Person or a combination thereof. For purposes of this definition, a Person is deemed to have a majority ownership interest in a partnership, limited liability company, association or other business entity if such Person is allocated a majority of the gains or losses of such partnership, limited liability company, association or other entity or is or controls the managing director or general partner of such partnership, limited liability company, association or other business entity.

“Tag Portion” means an amount of Membership Interests equal to the specified quantity of Tag-Along Offered Membership Interests multiplied by the applicable Investor Member’s Percentage Interest.

“Tax” or “Taxes” means any federal, state, local or foreign taxes, including income, gross receipts, capital stock, capital gains, franchise, profits, license, withholding, payroll, social security,

unemployment, disability, real property, ad valorem/personal property, stamp, excise, occupation, sales, use, excise, transfer, value added, import, export, alternative minimum, estimated or other tax, duty, assessment or governmental charge in the nature of a tax, including any interest, penalty or addition thereto.

“Tax Return” means any return, claim for refund, report, election, form, statement or information return relating to Taxes, including any schedule or attachment thereto, and including any amendments thereof.

“Third Party” means, with respect to a Member, another Person that is not another Member or an Affiliate of a Member.

“Transfer” shall mean, with respect to the legal or beneficial ownership of any of a Member’s Membership Interests, any sale, assignment, transfer, pledge, encumbrance, hypothecation or other similar arrangement or disposal, directly or indirectly, whether voluntarily, involuntarily or by operation of applicable Law (through a Change in Control or otherwise) including by the entry into any contract, option or other arrangement, or the granting or imposition of any Lien, that gives any Person other than the Member, whether or not upon the occurrence or nonoccurrence of an event, the right to acquire any Membership Interests or any interest therein, to vote any Membership Interest, or to require that any Membership Interests be transferred, directly or indirectly, whether voluntarily, involuntarily or by operation of applicable Law. For the avoidance of doubt and notwithstanding the foregoing, none of the following shall constitute a Transfer: (i) a sale, assignment, transfer, or other disposition of Equity Interests in any Member or any direct or indirect parent of such Member in which such Member represents less than fifty percent (50%) of the Fair Market Value of all of the assets directly or indirectly held by such Member or direct or indirect parent the Equity Interests of which are being disposed, except in any such case as expressly set forth in Section 6.2(b), (ii) a Change in Control of the NiSource Member, (iii) indirect transfers of Membership Interests resulting solely from acquisitions and dispositions of Equity Interests of Blackstone Inc., Parent or their respective Affiliates on the New York Stock Exchange, (iv) Change in Control of or any other sale, assignment, transfer, or other disposition of Equity Interests in the Parent, (v) any direct or indirect transfer to a Permitted Transferee of Equity Interests in either Investor Member that does not result in a Change in Control of such Investor Member, (vi) any direct or indirect transfer of Equity Interests in the NiSource Member that does not result in a Change in Control of the NiSource Member and (vii) as permitted under Section 6.2(b).

“Zonal Resource Credits” shall have the meaning defined in Module E of the Midcontinent Independent System Operator (MISO) Tariff.

Section 13.17 Terms Defined Elsewhere in this Agreement. As used in this Agreement, the following terms shall have the meanings ascribed to them in the sections indicated:

<u>Term</u>	<u>Section</u>
AAA	Section 13.13(a)
Affiliate Agreement Default	Section 2.14(c)
Affiliate Agreement Default Notice	Section 2.14(c)
Affiliate Agreements	Section 2.14(a)
Agreement	Preamble
BIP Investor Member	Preamble
BIP Investor Initial Contribution	Recitals
Blocker Seller	Section 6.7
Board	Section 2.1

Board Observer	Section 2.13
Call Consummation Period	Section 5.1(e)
Call Exercise Price	Section 5.1(e)
Call Notice	Section 5.1(e)
Call Right	Section 5.1(e)
Capital Request Funding Date	Section 5.1(a)
Capital Request Notice	Section 5.1(a)
Company	Preamble
Company Business	Section 1.3(a)
Confidential Information	Section 9.6(a)
Contributing Member	Section 5.1(b)(ii)
Contribution Unfunded Amount Notice	Section 5.1(b)
Corporate Opportunity	Section 9.3(b)
Cure Period	Section 5.1(e)
Defaulting Member	Section 4.2
Designated Alternate	Section 2.2(e)
Directors	Section 2.1
Drag-Along Buyer	Section 6.5(a)
Drag-Along Notice	Section 6.5(b)
Drag-Along Right	Section 6.5(a)
Drag-Along Sale	Section 6.5(a)
Event of Default	Section 4.1
Event of Dissolution	Section 4.3(a)
Excess Contribution	Section 5.1(b)(i)
Fund Indemnitees	Section 11.7
Fund Indemnitors	Section 11.7
GenCo	Recitals
GenCo Offtake Agreement	Section 1.3(iv)
Independent Evaluator	Section 13.15
Investor Directors	Section 2.2(b)
Investor Initial Contribution	Recitals
Investor Members	Preamble
Investor Offer	Section 6.3(a)(i)(B)
Investor Sale Notice	Section 6.3(a)(i)(A)
Lock-Up Period	Section 6.1(b)
Mandatory Capital Contribution	Section 5.1(a)
Management Update Meeting	Section 2.7(b)
NHII	Recitals
NiSource Directors	Section 2.2(d)
NiSource Member	Preamble
NiSource Sale Notice	Section 6.3(a)(i)(B)
Non-Transferring Member	Section 6.3(a)
Over-Contributing Member	Section 5.1(b)(i)
Parent	Preamble
Partnership Representative	Section 10.2
Party	Preamble

Preemptive Right
Preemptive Right Notice Period

Section 7.1
Section 7.1

Preemptive Right Participation Notice	Section 7.1
Pro Rata Request Amount	Section 5.1(a)
Regulatory Allocations	Section 5.7(h)
Response To Capital Call	Section 5.1(a)
Sale Period	Section 6.3(a)(ii)
Senior Management Termination Event	Schedule 2
Senior Management Member	Schedule 2
Subject Membership Interests	Section 6.3(a)
Tag-Along Buyer	Section 6.4(a)
Tag-Along Notice	Section 6.4(a)
Tag-Along Offered Membership Interests	Section 6.4(a)
Tag-Along Sale	Section 6.4(a)
Threshold Price	Section 6.3(a)(ii)
Total Number of Directors	Section 2.2(a)
Transferring Member	Section 6.3(a)
Unfunded Amount	Section 5.1(b)
Unfunded Amount Loan	Section 5.1(b)(ii)(A)
VCOC Investor Member	Preamble
VCOC Investor Initial Contribution	Recitals

Section 13.18 Other Definitional Provisions. The following shall apply to this Agreement:

(a) Accounting terms which are not otherwise defined in this Agreement have the meanings given to them under GAAP. To the extent that the definition of an accounting term defined in this Agreement is inconsistent with the meaning of such term under GAAP, the definition set forth in this Agreement shall control.

(b) The terms “hereof,” “herein” and “hereunder” and terms of similar import are references to this Agreement as a whole and not to any particular provision of this Agreement. Section, clause, schedule and exhibit references contained in this Agreement are references to sections, clauses, schedules and exhibits in or to this Agreement, unless otherwise specified.

(c) Whenever the words “include,” “includes” or “including” are used in this Agreement, they shall be deemed to be followed by the words “without limitation.” Where the context permits, the use of the term “or” shall be equivalent to the use of the term “and/or.”

(d) When calculating the period of time before which, within which or following which any act is to be done or step taken pursuant to this Agreement, the date that is the reference date in calculating such period shall be excluded. If the last day of such period is a day other than a Business Day, the period in question shall end on the next succeeding Business Day. In addition, notwithstanding any deadline for payment, performance, notice or election under this Agreement, if such deadline falls on a date that is not a Business Day, then the deadline for such payment, performance, notice or election will be extended to the next succeeding Business Day.

(e) Words denoting any gender shall include all genders, including the neutral gender. Where a word is defined herein, references to the singular shall include references to the plural and vice versa.

(f) The word “will” will be construed to have the same meaning and effect as the word “shall”. The words “shall,” “will,” or “agree(s)” are mandatory, and “may” is permissive.

(g) All references to “\$” and dollars shall be deemed to refer to United States currency unless otherwise specifically provided.

(h) All references to a day or days shall be deemed to refer to a calendar day or calendar days, as applicable, unless otherwise specifically provided.

(i) Any reference to any Contract shall be a reference to such agreement or Contract, as amended, amended and restated, modified, supplemented or waived.

(j) Any reference to any particular Code section or any Law shall be interpreted to include any amendment to, revision of or successor to that section or Law regardless of how it is numbered or classified; provided, that, for the purposes of the representations and warranties contained herein, with respect to any violation of or non-compliance with, or alleged violation of or non-compliance, with any Code section or Law, the reference to such Code section or Law means such Code section or Law as in effect at the time of such violation or non-compliance or alleged violation or non-compliance.

(k) For all purposes of this Agreement (including the determination of a Member's Percentage Interest and its entitlement, if applicable, to designate one or more Directors), such Member and its Permitted Transferees shall be deemed to be, and shall be treated as, one and the same Member.

[Remainder of Page Intentionally Left Blank]

IN WITNESS WHEREOF, the undersigned has duly executed this Agreement as of the date first written above.

The Company:

Generation Holdings II LLC

By: /s/ Shawn Anderson

Name: Shawn Anderson

Title: Executive Vice President and Chief Financial Officer

[Signature Page to A&R LLCA Generation Holdings II LLC]

IN WITNESS WHEREOF, the undersigned has duly executed this Agreement as of the date first written above.

NiSource Member:

Generation Holdings I LLC

By: /s/ Shawn Anderson

Name: Shawn Anderson

Title: Executive Vice President and Chief Financial Officer

Solely with respect to Article VI:

Parent:

NiSource Inc.

By: /s/ Shawn Anderson

Name: Shawn Anderson

Title: Executive Vice President and Chief Financial Officer

[Signature Page to A&R LLCA Generation Holdings II LLC]

IN WITNESS WHEREOF, the undersigned has duly executed this Agreement as of the date first written above.

BIP Investor Member:

BIP Orion Holdco II L.P.

By: BIP Holdings Manager L.L.C., its managing member

By: /s/ Sebastien Sherman

Name: Sebastien Sherman

Title: Senior Managing Director

VCOC Investor Member:

BIP Orion Holdco II L.P.

By: BIP Holdings Manager L.L.C., its managing member

By: /s/ Sebastien Sherman

Name: Sebastien Sherman

Title: Senior Managing Director

[Signature Page to A&R LLCA Generation Holdings II LLC]

Schedule 1
Schedule of Members

SCHEDULE 2
Senior Management Termination Event

Appendix A
PROHIBITED COMPETITORS

NiSource Inc.
2020 Omnibus Incentive Plan

202[] Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the “Agreement”), is made and entered into as of [DATE] (the “Grant Date”), by and between NiSource Inc., a Delaware corporation (the “Company”), and [NAME], an Employee of the Company or an Affiliate (the “Grantee”), pursuant to the terms of the NiSource Inc. 2020 Omnibus Incentive Plan, as amended (the “Plan”). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control.

Section 1. Restricted Stock Unit Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, an Award of [insert number of units] Restricted Stock Units. The Restricted Stock Units shall be represented by a bookkeeping entry (the “RSU Account”) of the Company, and each Restricted Stock Unit shall be equivalent to one share of the Company’s common stock.

Section 2. Grantee Accounts. The number of Restricted Stock Units granted pursuant to this Agreement shall be credited to the Grantee’s RSU Account. Each RSU Account shall be maintained on the books of the Company until full payment of the balance thereof has been made to the Grantee (or the Grantee’s beneficiaries or estate if the Grantee is deceased) in accordance with Section 1 above. No funds shall be set aside or earmarked for any RSU Account, which shall be purely a bookkeeping device.

Section 3. Vesting and Lapse of Restrictions.

- (a) Vesting. Subject to the forfeiture conditions described later in this Agreement, the Restricted Stock Units shall vest on [insert date with three-year cliff vesting] (the “Vesting Date”), at which date they shall become 100% vested, provided that the Grantee is continuously employed by the Company through and including the Vesting Date.
 - (b) Pro Rata or Accelerated Vesting. If the Grantee's Service is terminated for any reason (other than for Cause) prior to the Vesting Date, the restrictions set forth in subsection (a) above shall lapse and the Grantee shall vest in a *pro rata* or accelerated portion of such Restricted Share Units on the date of termination of Service for any reason in accordance with the attached Vesting Schedule. If subject to *pro rata* vesting, the lapse of restrictions shall be determined using a fraction, where the numerator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the date the Grantee terminates Service for any reason (other than for Cause), and the denominator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and Vesting Date.
-

- (c) Change in Control; Good Reason. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Restricted Stock Units under this Agreement shall be subject to the Change in Control provisions set forth in the Plan. Notwithstanding the foregoing or anything herein to the contrary, in the event the Restricted Stock Units do not become Alternative Awards under the Plan, then the Restricted Stock Units shall be settled within 60 days following the Change in Control; provided, however, in the event the Restricted Stock Units constitute nonqualified deferred compensation subject to Code Section 409A and the Change in Control is not a “change in control event” within the meaning of Code Section 409A, then, to the extent required to comply with Code Section 409A, the vested Restricted Stock Units shall be settled within 60 days following the Vesting Date or, if earlier and subject to Section 4, upon Grantee’s termination of Service. Notwithstanding any other agreement between the Company and the Grantee, the “Good Reason” definition set forth in the Plan shall govern this award.

Section 4. Delivery of Shares. Once Restricted Stock Units have vested under this Agreement, the Company shall convert the Restricted Stock Units in the Grantee’s RSU Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date or, if earlier, Grantee’s termination of Service in accordance with Section 3(b). Notwithstanding the foregoing, to the extent any portion of the Restricted Stock Units are subject to Code Section 409A, if any Restricted Stock Units vest prior to the Vesting Date in connection with a Grantee’s “separation from service” within the meaning of Code Section 409A and the Grantee is a “specified employee” within the meaning of Code Section 409A at the time of such separation from service, the Shares represented by the vested Restricted Stock Units shall be issued and delivered on the first business day after the date that is six (6) months following the date of the Grantee’s separation from service (or if earlier, the Grantee’s date of death). The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has distributed any portion of the vested Restricted Stock Units, the Company shall transfer any Shares payable with respect to the vested Restricted Stock Units in accordance with the Grantee’s written beneficiary designation or to the Grantee’s estate if no written beneficiary designation is provided.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Restricted Stock Units or the payment of any cash pursuant to Section 9 hereof, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the “Required Tax Payments”) with respect to the Restricted Stock Units and any such cash payments. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments with respect to any Restricted Stock Units by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes

first arises in connection with the Restricted Stock Units (the “Tax Date”), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Restricted Stock Units, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full. For any cash payments made pursuant to Section 9 hereof, the Company shall withhold from such cash payments the Required Tax Payments.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company’s obligation to issue or deliver certificates evidencing the Restricted Stock Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Restricted Stock Units shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Code Section 409A, the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company’s Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Restricted Stock Units have vested under this Agreement, the Restricted Stock Units granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Restricted Stock Units.

Section 8. Grantee’s Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee’s RSU Account or any other specific assets of the Company. All amounts credited to the Grantee’s RSU Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes, as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee; Dividend Equivalent Cash Payments.

- (a) Unless and until Shares have been issued to the Grantee, the Grantee shall not have any privileges of a stockholder of the Company with respect to any Restricted Stock Units subject to this Agreement, nor shall the Company have any obligation to issue any dividends or otherwise afford any rights to which Shares are entitled with respect to any such Restricted Stock Units. Notwithstanding the foregoing, in the event that the Company declares a cash dividend or cash distribution on Shares, on the payment date of the dividend or distribution, the Grantee will be entitled to receive a cash payment equal to the amount of the cash dividend or distribution per Share multiplied by the number of Restricted Stock Units granted by this Agreement and held by the Grantee on the dividend's or distribution's record date (as adjusted for any proration). The cash payable to the Grantee under the preceding sentence, less any taxes required to be withheld under Section 5 hereof, will be distributed to the Grantee as soon as practicable after the date on which the respective cash dividend or distribution is paid to holders of Shares.
- (b) Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the Award is outstanding, the number of outstanding Restricted Stock Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Restricted Stock Units shall be adjusted in accordance with the provisions of the Plan. In the event of certain corporate events specified in the Change in Control provisions of the Plan, any Restricted Stock Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271, or at such other address as the Company may designate by notice to the Grantee. Any notice hereunder by the Company shall be given to the Grantee in writing and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement at all times shall be governed by the Plan, which is incorporated in this Agreement by reference, and in no way alter or modify the Plan. To the extent a conflict exists between this Agreement and the Plan, the provisions of the Plan shall govern. This Agreement is pursuant to the terms of the Plan.

Section 15. Code Section 409A Compliance. This Agreement shall be interpreted in accordance with Code Section 409A including the rules related to payment timing for “specified employees” within the meaning of Code Section 409A. This Agreement shall be deemed to be modified to the maximum extent necessary to be in compliance with Code Section 409A’s rules. If the Grantee is unexpectedly required to include in the Grantee’s current year’s income any amount of compensation relating to the Restricted Stock Units because of a failure to meet the requirements of Code Section 409A, then to the extent permitted by Code Section 409A, the Grantee may receive a distribution of cash or Shares in an amount not to exceed the amount required to be included in income as a result of the failure to comply with Code Section 409A.

Section 16. Restrictive Covenant.

-) The Grantee understands the nature of the Company's business and the significant time and expense the Company and its Affiliates (collectively referred to in this Section as “NiSource”) have expended and continue to expend in attracting, developing, recruiting and training employees and that the loss of employees would cause significant and irreparable harm to NiSource. Accordingly, the Grantee agrees that the scope and duration of the restriction described in this Section 16 is reasonable and necessary to protect the legitimate business interests of NiSource. The Grantee agrees that during the period of the Grantee's Service and for a period of one (1) year following the Grantee's separation from Service, the Grantee shall not, without the express written approval of NiSource's Chief Human Resources Officer, directly or indirectly solicit, hire, recruit, or attempt to solicit, hire, or recruit, any then-current employee of NiSource or any employee who has been employed by NiSource in the six (6) months preceding such solicitation, hiring, or recruitment (“Covered Employee”). Soliciting, recruiting, or hiring Covered Employees with whom Grantee did not work or have direct contact while at NiSource to work as an employee, contractor, consultant or otherwise, shall not be considered a violation of this Section 16(a), provided, however, that Grantee does not solicit, employ or hire such employee with an intent to compete with NiSource in violation of this Section 16(a). Notwithstanding the foregoing, nothing in this Section shall restrict or preclude the Grantee from soliciting or hiring any employee who responds to a general employment solicitation or advertisement or contact by a recruiter that is not specifically focused or targeted on employees or former employees of NiSource, provided that the Grantee has not encouraged or advised such.

-) If the final judgment of a court of competent jurisdiction declares that any term or provision of this Section is invalid or unenforceable, the parties agree that (a) the court making the determination of invalidity or unenforceability shall have the power to reduce the scope, duration, or geographic area of the term or provision, to delete specific words or phrases, or to replace any invalid or unenforceable term or provision with a term or provision that is valid and enforceable and that comes closest to expressing the intention of the invalid or unenforceable term or provision, (b) the parties shall request that the court exercise that power, and (c) this Agreement in its revised form shall be enforceable.
-) Grantee agrees that in the event of a breach or threatened breach of the covenants contained in Section 16(a), in addition to any other damages or restrictions that may apply under any employment agreement, state law, or otherwise, the Grantee shall forfeit, upon written notice to such effect from the Company, any and all Awards granted to the Grantee under this Agreement, including vested Awards and including any proceeds thereof. The forfeiture provisions of this Section shall continue to apply, in accordance with their terms, after the provisions of any employment or other agreement between the Company and the Grantee have lapsed. Grantee expressly acknowledges that any breach or threatened breach of any of the terms and/or conditions of this Section 16 may result in substantial, continuing, and irreparable injury to NiSource, and therefore agrees that, in addition to any other remedy that may be available to NiSource, NiSource shall be entitled to seek injunctive relief, specific performance, or other equitable relief (without the requirement to post bond) by a court of appropriate jurisdiction in the event of any breach or threatened breach of the terms of this Section 16 without the necessity of proving irreparable harm or injury as a result of such breach or threatened breach. Grantee expressly acknowledges that Grantee's violation of this Section 16 will entitle NiSource to other equitable and legal remedies, including damages, attorney's fees, and costs, as allowed by law. The provisions of this Section 16 shall continue to apply, in accordance with their terms, after the Grantee's Service has terminated and regardless of whether the provisions of any employment or other agreement between the Company and the Grantee have lapsed.
-) In the event the Grantee is required to forfeit outstanding vested Shares as a result of breaching the Grantee's obligations under this Section 16, the Grantee agrees to promptly execute such stock powers or other instruments of transfer in such forms as are acceptable to the Company without payment or other consideration therefor.

IN WITNESS WHEREOF, the Company has caused this Award to be granted, and the Grantee has accepted this Award, as of the date first above written.

NISOURCE INC.

 /s/ Melanie Berman

By: Melanie Berman

Its: Senior Vice President and Chief Human Resources Officer

VESTING SCHEDULE

Awards granted in 2025:

- Termination at any time during 2025, the award vests in pro rata.
- Termination at any time between January 1, 2026 and the Vesting Date, the award is accelerated and becomes fully vested.

CEO

NiSource Inc.
2020 Omnibus Incentive Plan
202[] Performance Share Unit Award Agreement

This Performance Share Unit Award Agreement (the “Agreement”) is made and entered into as of [DATE] (the “Grant Date”), by and between NiSource Inc., a Delaware corporation (the “Company”), and [NAME], an Employee of the Company or an Affiliate (the “Grantee”), pursuant to the terms of the NiSource Inc. 2020 Omnibus Incentive Plan, as amended (the “Plan”). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control.

Section 1. Performance Share Unit Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of [insert number of units] Performance Share Units (the “Target Total Award” or “TTA”). The Performance Share Units shall be represented by a bookkeeping entry with respect to the Grantee (the “PSU Account”), and each Performance Share Unit shall be settled in one Share, to the extent provided under this Agreement and the Plan. This Agreement and the award shall be null and void unless the Grantee accepts this Agreement electronically within the Grantee’s stock plan account with the Company’s stock plan administrator according to the procedures then in effect.

Section 2. Performance-Based Vesting Conditions.

(a) **General.** Subject to the remainder of this Agreement, the TTA shall vest pursuant to the terms of this Agreement and the Plan based on the achievement of the performance goals set forth in this Section 2 over the performance period [insert three year performance period] (the “Performance Period”), with a vesting date of _ through [insert date after three year performance period] (the “Vesting Date”), provided that the Grantee remains in continuous Service through the Vesting Date. Attainment of the performance goals shall be determined and certified by the Compensation and Human Capital Committee of the Board of Directors of the Company (the “Committee”) prior to the settlement of the TTA.

(b) **[insert metric] Performance Goal.** Subject to the terms of this Agreement and the Plan, [insert number of performance share units for this metric] Performance Share Units ([] % of the TTA) shall be eligible to vest based on the Company’s achievement of [] during the Performance Period, as follows:

Performance Level(1)	[Insert metric]	Percentage _____ of the TTA Eligible for Vesting
Trigger	[]	[]%
Target	[]	[]%
Stretch	[]	[]%

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(c) [insert metric] Performance Goals.

(1) Subject to the terms of this Agreement and the Plan, [insert number of performance share units for this metric] of the Performance Share Units ([] % of the TTA) shall be eligible to vest based on the Company’s achievement of [] goals during the Performance Period, as follows:

LTI Metrics-Measure	TTA Weighting	Trigger	Target	Stretch
[insert metrics]				

(2) The total of the weighted levels of achievement for the performance measures described in Section 2(c)(1) above shall be aggregated and the percentage of Performance Share Units eligible to vest under Section 2(c) shall vest in the respective percentages set forth below, as applicable.

Performance Levels(1)	Percentage of the TTA Vesting Based on Achievement
Trigger	[]
Target	[]
Stretch	[]

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(d) Definitions.

[insert metric definitions.]

Section 3. Termination of Employment.

- (a) Vesting. Subject to the conditions described later in this Agreement, the Performance Share Units shall vest on [insert date following performance period] based on actual performance results, provided that the Grantee is continuously employed by the Company through the Vesting Date.
- (b) Pro Rata or Accelerated Vesting Upon Termination of Service. If the Grantee's Service is terminated for any reason prior to the Vesting Date (other than for Cause, Disability or Death), then the Grantee shall vest in a *pro rata* or accelerated portion of such Performance Share Units in accordance with the attached Vesting Schedule, based on the actual performance results for the Performance Period. If subject to *pro rata* vesting, the pro rata portion of the Performance Share Units shall be determined by multiplying the number of Performance Share Units earned based on actual performance by a fraction, where the numerator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the date the Grantee terminates Service for any reason (other than for Cause, Disability or Death), and the denominator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the Vesting Date.
- (c) Effect of Termination of Service due to Disability or Death.
- (1) Notwithstanding the foregoing, in the event that the Grantee's Service terminates on or prior to the Vesting Date as a result of the Grantee's Disability, or (ii) death and such death occurs with less than or equal to twelve months remaining in the Performance Period, then the Grantee (or the Grantee's beneficiary or estate in the case of the Grantee's death) shall vest in a *pro rata* portion of the Performance Share Units, based on the actual performance results for the Performance Period. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of Performance Share Units earned based on actual performance by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.
- (2) Notwithstanding the foregoing, in the event that the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the Performance Period, then the Grantee's beneficiary or estate shall vest, on the date of termination of Service, in a *pro rata* portion of the target Performance Share Units. Such *pro rata* portion of the Performance

Share Units shall be determined by multiplying the number of target Performance Share Units by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.

- (d) Change in Control; Good Reason. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Share Units under this Agreement shall be subject to the Change in Control provisions set forth in the Plan. Notwithstanding any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in the Plan shall govern this award."

Section 4. Delivery of Shares. Subject to the terms of this Agreement and except as otherwise provided for herein, the Company shall convert the Performance Share Units in the Grantee's PSU Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date (but in any event no later than the March 15th immediately following the year in which the substantial risk of forfeiture with respect to the Performance Share Units lapses) or, if earlier, within 30 days following (a) the Grantee's death in accordance with Section 3(c)(2), (b) Grantee's termination of Service without Cause or due to Good Reason in accordance with the Change in Control provisions of the Plan or (c) a Change in Control in the event the Performance Share Units do not become Alternative Awards under the Plan. The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has issued or distributed the vested Performance Share Units, the Company shall transfer any Shares with respect to the vested Performance Share Units in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided. The issuance or delivery of the Shares hereunder shall be evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such issuance or delivery, except as otherwise provided in Section 5.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Performance Share Units, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the "Required Tax Payments") with respect to the Performance Share Units. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Performance Share Units (the "Tax Date"), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Performance Share Units, a number

of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Performance Share Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Performance Share Units shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Code Section 409A, the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Share Units have vested under this Agreement, the Performance Share Units granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Performance Share Units.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's PSU Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's PSU Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee; Dividend Equivalent Rights.

- (a) Unless and until Shares have been issued to the Grantee, the Grantee shall not have any privileges of a stockholder of the Company with respect to any Performance Share Units subject to this Agreement, nor shall the Company have any obligation to issue any dividend or otherwise afford any rights to which Shares are entitled with respect to any such Performance Share Units. Notwithstanding the foregoing, in the event that the Company declares a cash dividend or distribution on Shares,

the Grantee will be credited with Dividend Equivalent Rights equal to the amount of the cash dividend or distribution per Share multiplied by the number of Performance Share Units granted by this Agreement and held by the Grantee on the dividend's or distribution's record date (as adjusted for any proration). The Dividend Equivalent Rights credited to the Grantee under the preceding sentence will be deemed to be reinvested in additional Performance Share Units, which will be subject to the same terms regarding vesting, forfeiture, and Dividend Equivalent Rights as Performance Share Units awarded to the Grantee under this Agreement. Following the Performance Period, the Grantee will be entitled to receive a cash payment equal to the value of the accrued Dividend Equivalent Rights (as adjusted for any proration) multiplied by the vested percentage of the TTA determined under Sections 2(b), 2(c) and 2(d) above.

- (b) Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the Award is outstanding, the number of outstanding Performance Share Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan (in each case as determined by the Committee), the number and kind of Performance Share Units and the performance goals, as applicable, shall be adjusted in accordance with the provisions of the Plan. In the event of certain corporate events specified in the Change in Control provisions of the Plan, any Performance Share Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan, as determined by the Committee.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing, and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271 (or at such other address as the Company may designate by notice to the Grantee). Any notice hereunder by the Company shall be given to the Grantee in writing, and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is subject to the provisions of the Plan and shall be interpreted in accordance therewith. In the event that the provisions of this Agreement and the Plan conflict, the Plan shall control. The Grantee hereby acknowledges receipt of a copy of the Plan.

Section 15. Code Section 409A Compliance. This Agreement and the Performance Share Units granted hereunder are intended to be exempt from Code Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

Section 16. Restrictive Covenant.

- (a) The Grantee understands the nature of the Company's business and the significant time and expense the Company and its Affiliates (collectively referred to in this Section as "NiSource") have expended and continue to expend in attracting, developing, recruiting and training employees and that the loss of employees would cause significant and irreparable harm to NiSource. Accordingly, the Grantee agrees that the scope and duration of the restriction described in this Section 16 is reasonable and necessary to protect the legitimate business interests of NiSource. The Grantee agrees that during the period of the Grantee's Service and for a period of one (1) year following the Grantee's separation from Service, the Grantee shall not, without the express written approval of NiSource's Chief Human Resources Officer, directly or indirectly solicit, hire, recruit, or attempt to solicit, hire, or recruit, any then-current employee of NiSource or any employee who has been employed by NiSource in the six (6) months preceding such solicitation, hiring, or recruitment ("Covered Employee"). Soliciting, recruiting, or hiring Covered Employees with whom Grantee did not work or have direct contact while at NiSource to work as an employee, contractor, consultant or otherwise, shall not be considered a violation of this Section 16(a), provided, however, that Grantee does not solicit, employ or hire such employee with an intent to compete with NiSource in violation of this Section 16(a). Notwithstanding the foregoing, nothing in this Section shall restrict or preclude the Grantee from soliciting or hiring any employee who responds to a general employment solicitation or advertisement or contact by a recruiter that is not specifically focused or targeted on employees or former employees of NiSource, provided that the Grantee has not encouraged or advised such.
- (b) If the final judgment of a court of competent jurisdiction declares that any term or provision of this Section is invalid or unenforceable, the parties agree that (a) the court making the determination of invalidity or unenforceability shall have the power to reduce the scope, duration, or geographic area of the term or provision, to delete specific words or phrases, or to replace any invalid or unenforceable term or provision with a term or provision that is valid and enforceable and that comes closest to expressing the intention of the invalid or unenforceable term or

provision, (b) the parties shall request that the court exercise that power, and (c) this Agreement in its revised form shall be enforceable.

- (c) Grantee agrees that in the event of a breach or threatened breach of the covenants contained in Section 16(a), in addition to any other damages or restrictions that may apply under any employment agreement, state law, or otherwise, the Grantee shall forfeit, upon written notice to such effect from the Company, any and all Awards granted to the Grantee under this Agreement, including vested Awards and including any proceeds thereof. The forfeiture provisions of this Section shall continue to apply, in accordance with their terms, after the provisions of any employment or other agreement between the Company and the Grantee have lapsed. Grantee expressly acknowledges that any breach or threatened breach of any of the terms and/or conditions of this Section 16 may result in substantial, continuing, and irreparable injury to NiSource, and therefore agrees that, in addition to any other remedy that may be available to NiSource, NiSource shall be entitled to seek injunctive relief, specific performance, or other equitable relief (without the requirement to post bond) by a court of appropriate jurisdiction in the event of any breach or threatened breach of the terms of this Section 16 without the necessity of proving irreparable harm or injury as a result of such breach or threatened breach. Grantee expressly acknowledges that Grantee's violation of this Section 16 will entitle NiSource to other equitable and legal remedies, including damages, attorney's fees, and costs, as allowed by law. The provisions of this Section 16 shall continue to apply, in accordance with their terms, after the Grantee's Service has terminated and regardless of whether the provisions of any employment or other agreement between the Company and the Grantee have lapsed.
- (d) In the event the Grantee is required to forfeit outstanding vested Shares as a result of breaching the Grantee's obligations under this Section 16, the Grantee agrees to promptly execute such stock powers or other instruments of transfer in such forms as are acceptable to the Company without payment or other consideration therefor.

IN WITNESS WHEREOF, the Company has caused the Performance Share Units subject to this Agreement to be granted, and the Grantee has accepted the Performance Share Units subject to the terms of the Agreement, as of the date first above written.

NISOURCE INC.

 /s/ Melanie Berman

By: Melanie Berman

Its: Senior Vice President and Chief Human Resources Officer

VESTING SCHEDULE

Awards granted in 2025, for the 2025-2027 Performance Period:

- Termination at any time during 2025, the award vests in pro rata.
- Termination at any time between January 1, 2026 and the Vesting Date, the award is accelerated and becomes fully vested.

NiSource Inc.
2020 Omnibus Incentive Plan

202[] Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the “Agreement”), is made and entered into as of [DATE] (the “Grant Date”), by and between NiSource Inc., a Delaware corporation (the “Company”), and [NAME], an Employee of the Company or an Affiliate (the “Grantee”), pursuant to the terms of the NiSource Inc. 2020 Omnibus Incentive Plan, as amended (the “Plan”). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control.

Section 1. Restricted Stock Unit Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, an Award of [insert number of units] Restricted Stock Units. The Restricted Stock Units shall be represented by a bookkeeping entry (the “RSU Account”) of the Company, and each Restricted Stock Unit shall be equivalent to one share of the Company’s common stock.

Section 2. Grantee Accounts. The number of Restricted Stock Units granted pursuant to this Agreement shall be credited to the Grantee’s RSU Account. Each RSU Account shall be maintained on the books of the Company until full payment of the balance thereof has been made to the Grantee (or the Grantee’s beneficiaries or estate if the Grantee is deceased) in accordance with Section 1 above. No funds shall be set aside or earmarked for any RSU Account, which shall be purely a bookkeeping device.

Section 3. Vesting and Lapse of Restrictions.

- (a) **Vesting.** Subject to the forfeiture conditions described later in this Agreement, the Restricted Stock Units shall vest on [insert date with three-year cliff vesting] (the “Vesting Date”), at which date they shall become 100% vested, provided that the Grantee is continuously employed by the Company through and including the Vesting Date.
 - (b) **Pro Rata or Full Vesting.** If the Grantee’s Service is terminated for any reason (other than for Cause) prior to the Vesting Date, the restrictions set forth in subsection (a) above shall lapse and the Grantee shall vest in a *pro rata* or full portion of such Restricted Share Units on the date of termination of Service for any reason in accordance with the attached Vesting Schedule. If subject to *pro rata* vesting, the lapse of restrictions shall be determined using a fraction, where the numerator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the date the Grantee terminates Service for any reason (other than for Cause), and the denominator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and Vesting Date.
 - (c) **Change in Control; Good Reason.** Notwithstanding the foregoing provisions, in the event of a Change in Control, the Restricted Stock Units under this Agreement
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shall be subject to the Change in Control provisions set forth in the Plan. Notwithstanding the foregoing or anything herein to the contrary, in the event the Restricted Stock Units do not become Alternative Awards under the Plan, then the Restricted Stock Units shall be settled within 60 days following the Change in Control; provided, however, in the event the Restricted Stock Units constitute nonqualified deferred compensation subject to Code Section 409A and the Change in Control is not a “change in control event” within the meaning of Code Section 409A, then, to the extent required to comply with Code Section 409A, the vested Restricted Stock Units shall be settled within 60 days following the Vesting Date or, if earlier and subject to Section 4, upon Grantee’s termination of Service. Notwithstanding any other agreement between the Company and the Grantee, the “Good Reason” definition set forth in the Plan shall govern this award.

Section 4. Delivery of Shares. Once Restricted Stock Units have vested under this Agreement, the Company shall convert the Restricted Stock Units in the Grantee’s RSU Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date or, if earlier, Grantee’s termination of Service in accordance with Section 3(b). Notwithstanding the foregoing, to the extent any portion of the Restricted Stock Units are subject to Code Section 409A, if any Restricted Stock Units vest prior to the Vesting Date in connection with a Grantee’s “separation from service” within the meaning of Code Section 409A and the Grantee is a “specified employee” within the meaning of Code Section 409A at the time of such separation from service, the Shares represented by the vested Restricted Stock Units shall be issued and delivered on the first business day after the date that is six (6) months following the date of the Grantee’s separation from service (or if earlier, the Grantee’s date of death). The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has distributed any portion of the vested Restricted Stock Units, the Company shall transfer any Shares payable with respect to the vested Restricted Stock Units in accordance with the Grantee’s written beneficiary designation or to the Grantee’s estate if no written beneficiary designation is provided.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Restricted Stock Units or the payment of any cash pursuant to Section 9 hereof, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the “Required Tax Payments”) with respect to the Restricted Stock Units and any such cash payments. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments with respect to any Restricted Stock Units by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Restricted Stock Units (the “Tax Date”), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered

to Grantee upon the vesting of the Restricted Stock Units, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full. For any cash payments made pursuant to Section 9 hereof, the Company shall withhold from such cash payments the Required Tax Payments.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Restricted Stock Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Restricted Stock Units shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Code Section 409A, the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Restricted Stock Units have vested under this Agreement, the Restricted Stock Units granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Restricted Stock Units.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's RSU Account or any other specific assets of the Company. All amounts credited to the Grantee's RSU Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes, as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee; Dividend Equivalent Cash Payments.

- (a) Unless and until Shares have been issued to the Grantee, the Grantee shall not have any privileges of a stockholder of the Company with respect to any Restricted

Stock Units subject to this Agreement, nor shall the Company have any obligation to issue any dividends or otherwise afford any rights to which Shares are entitled with respect to any such Restricted Stock Units. Notwithstanding the foregoing, in the event that the Company declares a cash dividend or cash distribution on Shares, on the payment date of the dividend or distribution, the Grantee will be entitled to receive a cash payment equal to the amount of the cash dividend or distribution per Share multiplied by the number of Restricted Stock Units granted by this Agreement and held by the Grantee on the dividend's or distribution's record date (as adjusted for any proration). The cash payable to the Grantee under the preceding sentence, less any taxes required to be withheld under Section 5 hereof, will be distributed to the Grantee as soon as practicable after the date on which the respective cash dividend or distribution is paid to holders of Shares.

- (b) Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the Award is outstanding, the number of outstanding Restricted Stock Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Restricted Stock Units shall be adjusted in accordance with the provisions of the Plan. In the event of certain corporate events specified in the Change in Control provisions of the Plan, any Restricted Stock Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271, or at such other address as the Company may designate by notice to the Grantee. Any notice hereunder by the Company shall be given to the Grantee in writing and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement at all times shall be governed by the Plan, which is incorporated in this Agreement by reference, and in no way alter or modify the Plan. To the extent a conflict exists between this Agreement and the Plan, the provisions of the Plan shall govern. This Agreement is pursuant to the terms of the Plan.

Section 15. Code Section 409A Compliance. This Agreement shall be interpreted in accordance with Code Section 409A including the rules related to payment timing for “specified employees” within the meaning of Code Section 409A. This Agreement shall be deemed to be modified to the maximum extent necessary to be in compliance with Code Section 409A’s rules. If the Grantee is unexpectedly required to include in the Grantee’s current year’s income any amount of compensation relating to the Restricted Stock Units because of a failure to meet the requirements of Code Section 409A, then to the extent permitted by Code Section 409A, the Grantee may receive a distribution of cash or Shares in an amount not to exceed the amount required to be included in income as a result of the failure to comply with Code Section 409A.

Section 16. Restrictive Covenant.

-) The Grantee understands the nature of the Company's business and the significant time and expense the Company and its Affiliates (collectively referred to in this Section as “NiSource”) have expended and continue to expend in attracting, developing, recruiting and training employees and that the loss of employees would cause significant and irreparable harm to NiSource. Accordingly, the Grantee agrees that the scope and duration of the restriction described in this Section 16 is reasonable and necessary to protect the legitimate business interests of NiSource. The Grantee agrees that during the period of the Grantee's Service and for a period of one (1) year following the Grantee's separation from Service, the Grantee shall not, without the express written approval of NiSource's Chief Human Resources Officer, directly or indirectly solicit, hire, recruit, or attempt to solicit, hire, or recruit, any then-current employee of NiSource or any employee who has been employed by NiSource in the six (6) months preceding such solicitation, hiring, or recruitment (“Covered Employee”). Soliciting, recruiting, or hiring Covered Employees with whom Grantee did not work or have direct contact while at NiSource to work as an employee, contractor, consultant or otherwise, shall not be considered a violation of this Section 16(a), provided, however, that Grantee does not solicit, employ or hire such employee with an intent to compete with NiSource in violation of this Section 16(a). Notwithstanding the foregoing, nothing in this Section shall restrict or preclude the Grantee from soliciting or hiring any employee who responds to a general employment solicitation or advertisement or contact by a recruiter that is not specifically focused or targeted on employees or former employees of NiSource, provided that the Grantee has not encouraged or advised such.

-) If the final judgment of a court of competent jurisdiction declares that any term or provision of this Section is invalid or unenforceable, the parties agree that (a) the court making the determination of invalidity or unenforceability shall have the power to reduce the scope, duration, or geographic area of the term or provision, to delete specific words or phrases, or to replace any invalid or unenforceable term or provision with a term or provision that is valid and enforceable and that comes closest to expressing the intention of the invalid or unenforceable term or provision, (b) the parties shall request that the court exercise that power, and (c) this Agreement in its revised form shall be enforceable.
-) Grantee agrees that in the event of a breach or threatened breach of the covenants contained in Section 16(a), in addition to any other damages or restrictions that may apply under any employment agreement, state law, or otherwise, the Grantee shall forfeit, upon written notice to such effect from the Company, any and all Awards granted to the Grantee under this Agreement, including vested Awards and including any proceeds thereof. The forfeiture provisions of this Section shall continue to apply, in accordance with their terms, after the provisions of any employment or other agreement between the Company and the Grantee have lapsed. Grantee expressly acknowledges that any breach or threatened breach of any of the terms and/or conditions of this Section 16 may result in substantial, continuing, and irreparable injury to NiSource, and therefore agrees that, in addition to any other remedy that may be available to NiSource, NiSource shall be entitled to seek injunctive relief, specific performance, or other equitable relief (without the requirement to post bond) by a court of appropriate jurisdiction in the event of any breach or threatened breach of the terms of this Section 16 without the necessity of proving irreparable harm or injury as a result of such breach or threatened breach. Grantee expressly acknowledges that Grantee's violation of this Section 16 will entitle NiSource to other equitable and legal remedies, including damages, attorney's fees, and costs, as allowed by law. The provisions of this Section 16 shall continue to apply, in accordance with their terms, after the Grantee's Service has terminated and regardless of whether the provisions of any employment or other agreement between the Company and the Grantee have lapsed.
-) In the event the Grantee is required to forfeit outstanding vested Shares as a result of breaching the Grantee's obligations under this Section 16, the Grantee agrees to promptly execute such stock powers or other instruments of transfer in such forms as are acceptable to the Company without payment or other consideration therefor.

IN WITNESS WHEREOF, the Company has caused this Award to be granted, and the Grantee has accepted this Award, as of the date first above written.

NISOURCE INC.

/s/ Melanie Berman

By: Melanie Berman

Its: Executive Vice President and Chief Human Resources Officer

VESTING SCHEDULE

- Termination at any time during [the first Calendar year of the grant], the award vests in pro rata.
- Termination at any time [after the first calendar year of the grant and before the Vesting Date], the award becomes fully vested.

CEO

NiSource Inc.
2020 Omnibus Incentive Plan
202[] Performance Share Unit Award Agreement

This Performance Share Unit Award Agreement (the “Agreement”) is made and entered into as of [DATE] (the “Grant Date”), by and between NiSource Inc., a Delaware corporation (the “Company”), and [NAME], an Employee of the Company or an Affiliate (the “Grantee”), pursuant to the terms of the NiSource Inc. 2020 Omnibus Incentive Plan, as amended (the “Plan”). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control.

Section 1. Performance Share Unit Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of [insert number of units] Performance Share Units (the “Target Total Award” or “TTA”). The Performance Share Units shall be represented by a bookkeeping entry with respect to the Grantee (the “PSU Account”), and each Performance Share Unit shall be settled in one Share, to the extent provided under this Agreement and the Plan. This Agreement and the award shall be null and void unless the Grantee accepts this Agreement electronically within the Grantee’s stock plan account with the Company’s stock plan administrator according to the procedures then in effect.

Section 2. Performance-Based Vesting Conditions.

(a) **General.** Subject to the remainder of this Agreement, the TTA shall vest pursuant to the terms of this Agreement and the Plan based on the achievement of the performance goals set forth in this Section 2 over the performance period [insert three year performance period] (the “Performance Period”), with a vesting date of _____ [insert date after three year performance period] (the “Vesting Date”), provided that the Grantee remains in continuous Service through the Vesting Date and subject to provisions in Section 3. Attainment of the performance goals shall be determined and certified by the Compensation and Human Capital Committee of the Board of Directors of the Company (the “Committee”) prior to the settlement of the TTA.

(b) **[insert metric] Performance Goal.** Subject to the terms of this Agreement and the Plan, [insert number of performance share units for this metric] Performance Share Units ([] % of the TTA) shall be eligible to vest based on the Company’s achievement of [] during the Performance Period, as follows:

Performance Level(1)	[Insert metric]	Percentage _____ of the TTA Eligible for Vesting
Trigger	[]	[]%
Target	[]	[]%
Stretch	[]	[]%

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(c) [insert metric] Performance Goals.

(1) Subject to the terms of this Agreement and the Plan, [insert number of performance share units for this metric] of the Performance Share Units ([] % of the TTA) shall be eligible to vest based on the Company’s achievement of [] goals during the Performance Period, as follows:

LTI Metrics-Measure	TTA Weighting	Trigger	Target	Stretch
[insert metrics]				

(2) The total of the weighted levels of achievement for the performance measures described in Section 2(c)(1) above shall be aggregated and the percentage of Performance Share Units eligible to vest under Section 2(c) shall vest in the respective percentages set forth below, as applicable.

Performance Levels(1)	Percentage of the TTA Vesting Based on Achievement
Trigger	[]
Target	[]
Stretch	[]

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(d) Definitions.

[insert metric definitions.]

Section 3. Termination of Employment.

- (a) Vesting. Subject to the conditions described later in this Agreement, the Performance Share Units shall vest on [insert date following performance period] based on actual performance results, provided that the Grantee is continuously employed by the Company through the Vesting Date.
- (b) Pro Rata or Full Vesting Upon Termination of Service. If the Grantee's Service is terminated for any reason prior to the Vesting Date (other than for Cause, Disability or Death), then the Grantee shall vest in a *pro rata* or full portion of such Performance Share Units in accordance with the attached Vesting Schedule, based on the actual performance results for the Performance Period. If subject to *pro rata* vesting, the pro rata portion of the Performance Share Units shall be determined by multiplying the number of Performance Share Units earned based on actual performance by a fraction, where the numerator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the date the Grantee terminates Service for any reason (other than for Cause, Disability or Death), and the denominator shall be the number of calendar months (whether full or partial months) elapsed between the Grant Date and the Vesting Date.
- (c) Effect of Termination of Service due to Disability or Death.
 - (1) Notwithstanding the foregoing, in the event that the Grantee's Service terminates on or prior to the Vesting Date as a result of the Grantee's Disability, or (ii) death and such death occurs with less than or equal to twelve months remaining in the Performance Period, then the Grantee (or the Grantee's beneficiary or estate in the case of the Grantee's death) shall vest in a *pro rata* portion of the Performance Share Units, based on the actual performance results for the Performance Period. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of Performance Share Units earned based on actual performance by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.
 - (2) Notwithstanding the foregoing, in the event that the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the Performance Period, then the Grantee's beneficiary or estate shall vest, on the date of termination of Service, in a *pro rata* portion of the target Performance Share Units. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of target

Performance Share Units by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.

- (d) Change in Control; Good Reason. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Share Units under this Agreement shall be subject to the Change in Control provisions set forth in the Plan. Notwithstanding any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in the Plan shall govern this award."

Section 4. Delivery of Shares. Subject to the terms of this Agreement and except as otherwise provided for herein, the Company shall convert the Performance Share Units in the Grantee's PSU Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date (but in any event no later than the March 15th immediately following the year in which the substantial risk of forfeiture with respect to the Performance Share Units lapses) or, if earlier, within 30 days following (a) the Grantee's death in accordance with Section 3(c)(2), (b) Grantee's termination of Service without Cause or due to Good Reason in accordance with the Change in Control provisions of the Plan or (c) a Change in Control in the event the Performance Share Units do not become Alternative Awards under the Plan. The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has issued or distributed the vested Performance Share Units, the Company shall transfer any Shares with respect to the vested Performance Share Units in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided. The issuance or delivery of the Shares hereunder shall be evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such issuance or delivery, except as otherwise provided in Section 5.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Performance Share Units, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the "Required Tax Payments") with respect to the Performance Share Units. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Performance Share Units (the "Tax Date"), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Performance Share Units, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax

Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Performance Share Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Performance Share Units shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Code Section 409A, the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Share Units have vested under this Agreement, the Performance Share Units granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Performance Share Units.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's PSU Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's PSU Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee; Dividend Equivalent Rights.

- (a) Unless and until Shares have been issued to the Grantee, the Grantee shall not have any privileges of a stockholder of the Company with respect to any Performance Share Units subject to this Agreement, nor shall the Company have any obligation to issue any dividend or otherwise afford any rights to which Shares are entitled with respect to any such Performance Share Units. Notwithstanding the foregoing, in the event that the Company declares a cash dividend or distribution on Shares, the Grantee will be credited with Dividend Equivalent Rights equal to the amount

of the cash dividend or distribution per Share multiplied by the number of Performance Share Units granted by this Agreement and held by the Grantee on the dividend's or distribution's record date (as adjusted for any proration). The Dividend Equivalent Rights credited to the Grantee under the preceding sentence will be deemed to be reinvested in additional Performance Share Units, which will be subject to the same terms regarding vesting, forfeiture, and Dividend Equivalent Rights as Performance Share Units awarded to the Grantee under this Agreement. Following the Performance Period, the Grantee will be entitled to receive a cash payment equal to the value of the accrued Dividend Equivalent Rights (as adjusted for any proration) multiplied by the vested percentage of the TTA determined under Sections 2(b), 2(c) and 2(d) above.

- (b) Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the Award is outstanding, the number of outstanding Performance Share Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan (in each case as determined by the Committee), the number and kind of Performance Share Units and the performance goals, as applicable, shall be adjusted in accordance with the provisions of the Plan. In the event of certain corporate events specified in the Change in Control provisions of the Plan, any Performance Share Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan, as determined by the Committee.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing, and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271 (or at such other address as the Company may designate by notice to the Grantee). Any notice hereunder by the Company shall be given to the Grantee in writing, and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any

previous agreements, written or oral, relating to the subject matter hereof. This Agreement is subject to the provisions of the Plan and shall be interpreted in accordance therewith. In the event that the provisions of this Agreement and the Plan conflict, the Plan shall control. The Grantee hereby acknowledges receipt of a copy of the Plan.

Section 15. Code Section 409A Compliance. This Agreement and the Performance Share Units granted hereunder are intended to be exempt from Code Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

Section 16. Restrictive Covenant.

- (a) The Grantee understands the nature of the Company's business and the significant time and expense the Company and its Affiliates (collectively referred to in this Section as "NiSource") have expended and continue to expend in attracting, developing, recruiting and training employees and that the loss of employees would cause significant and irreparable harm to NiSource. Accordingly, the Grantee agrees that the scope and duration of the restriction described in this Section 16 is reasonable and necessary to protect the legitimate business interests of NiSource. The Grantee agrees that during the period of the Grantee's Service and for a period of one (1) year following the Grantee's separation from Service, the Grantee shall not, without the express written approval of NiSource's Chief Human Resources Officer, directly or indirectly solicit, hire, recruit, or attempt to solicit, hire, or recruit, any then-current employee of NiSource or any employee who has been employed by NiSource in the six (6) months preceding such solicitation, hiring, or recruitment ("Covered Employee"). Soliciting, recruiting, or hiring Covered Employees with whom Grantee did not work or have direct contact while at NiSource to work as an employee, contractor, consultant or otherwise, shall not be considered a violation of this Section 16(a), provided, however, that Grantee does not solicit, employ or hire such employee with an intent to compete with NiSource in violation of this Section 16(a). Notwithstanding the foregoing, nothing in this Section shall restrict or preclude the Grantee from soliciting or hiring any employee who responds to a general employment solicitation or advertisement or contact by a recruiter that is not specifically focused or targeted on employees or former employees of NiSource, provided that the Grantee has not encouraged or advised such.
- (b) If the final judgment of a court of competent jurisdiction declares that any term or provision of this Section is invalid or unenforceable, the parties agree that (a) the court making the determination of invalidity or unenforceability shall have the power to reduce the scope, duration, or geographic area of the term or provision, to delete specific words or phrases, or to replace any invalid or unenforceable term or provision with a term or provision that is valid and enforceable and that comes closest to expressing the intention of the invalid or unenforceable term or provision, (b) the parties shall request that the court exercise that power, and (c) this Agreement in its revised form shall be enforceable.

- (c) Grantee agrees that in the event of a breach or threatened breach of the covenants contained in Section 16(a), in addition to any other damages or restrictions that may apply under any employment agreement, state law, or otherwise, the Grantee shall forfeit, upon written notice to such effect from the Company, any and all Awards granted to the Grantee under this Agreement, including vested Awards and including any proceeds thereof. The forfeiture provisions of this Section shall continue to apply, in accordance with their terms, after the provisions of any employment or other agreement between the Company and the Grantee have lapsed. Grantee expressly acknowledges that any breach or threatened breach of any of the terms and/or conditions of this Section 16 may result in substantial, continuing, and irreparable injury to NiSource, and therefore agrees that, in addition to any other remedy that may be available to NiSource, NiSource shall be entitled to seek injunctive relief, specific performance, or other equitable relief (without the requirement to post bond) by a court of appropriate jurisdiction in the event of any breach or threatened breach of the terms of this Section 16 without the necessity of proving irreparable harm or injury as a result of such breach or threatened breach. Grantee expressly acknowledges that Grantee's violation of this Section 16 will entitle NiSource to other equitable and legal remedies, including damages, attorney's fees, and costs, as allowed by law. The provisions of this Section 16 shall continue to apply, in accordance with their terms, after the Grantee's Service has terminated and regardless of whether the provisions of any employment or other agreement between the Company and the Grantee have lapsed.
- (d) In the event the Grantee is required to forfeit outstanding vested Shares as a result of breaching the Grantee's obligations under this Section 16, the Grantee agrees to promptly execute such stock powers or other instruments of transfer in such forms as are acceptable to the Company without payment or other consideration therefor.

IN WITNESS WHEREOF, the Company has caused the Performance Share Units subject to this Agreement to be granted, and the Grantee has accepted the Performance Share Units subject to the terms of the Agreement, as of the date first above written.

NISOURCE INC.

/s/ Melanie Berman

By: Melanie Berman

Its: Executive Vice President and Chief Human Resources Officer

VESTING SCHEDULE

- Termination at any time during [the first Calendar year of the grant], the award vests in pro rata.
- Termination at any time [after the first calendar year of the grant and before the Vesting Date], the award becomes fully vested.

SUBSIDIARIES OF NISOURCE INC.

as of December 31, 2025

Segment/Subsidiary	State of Incorporation
COLUMBIA OPERATIONS	
Columbia Gas of Kentucky, Inc.	Kentucky
Columbia Gas of Maryland, Inc.	Delaware
Columbia Gas of Ohio, Inc.	Ohio
Columbia Gas of Ohio Receivables Corporation	Delaware
Columbia Gas of Pennsylvania, Inc.	Pennsylvania
Columbia Gas of Pennsylvania Receivables Corporation	Delaware
Columbia Gas of Virginia, Inc.	Virginia
NiSource Gas Distribution Group, Inc.	Delaware
NIPSCO OPERATIONS	
Dunn's Bridge I Solar Generation LLC	Delaware
Dunns Bridge Solar Center, LLC	Delaware
Fairbanks Solar Energy Center LLC	Delaware
Gibson Solar, LLC	Delaware
Indiana Crossroads Solar Generation LLC	Delaware
Indiana Crossroads Wind Farm LLC	Delaware
Indiana Crossroads Wind Generation LLC	Delaware
Meadow Lake Solar Park LLC	Delaware
NIPSCO Accounts Receivable Corporation	Indiana
NIPSCO Holdings I LLC	Indiana
NIPSCO Holdings II LLC	Delaware
Northern Indiana Public Service Company LLC*	Indiana
RoseWater Wind Farm LLC	Delaware
RoseWater Wind Generation LLC	Delaware
CORPORATE AND OTHER OPERATIONS	
Bay State Gas Company	Massachusetts
Generation Holdings I LLC	Indiana
Generation Holdings II LLC	Delaware
Lake Erie Land Company	Indiana
NIPSCO Generation LLC	Indiana
NiSource Corporate Group, LLC	Delaware
NiSource Corporate Services Company	Delaware
NiSource Development Company, Inc.	Indiana
NiSource Energy Technologies, Inc.	Indiana
NiSource Insurance Corporation, Inc.	Utah

* Both Gas Distribution Operations and Electric Operations

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-291167 on Form S-3, Registration Statement Nos. 333-107743, 333-166888, 333-228102, 333-233382, 333-238501, 333-248405, 333-260906, 333-281526, and 333-291346 on Form S-8, and Registration Statement Nos. 333-228790 and 333-228791 on Form S-4 of our reports dated February 11, 2026, relating to the consolidated financial statements of NiSource Inc. and subsidiaries (the “Company”) and the effectiveness of the Company's internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 11, 2026

**Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002**

I, Lloyd M. Yates, certify that:

1. I have reviewed this Annual Report of NiSource Inc. on Form 10-K of NiSource Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2026

By:

/s/ Lloyd M. Yates

Lloyd M. Yates
President and Chief Executive Officer

**Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Lloyd M. Yates, Chief Executive Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Lloyd M. Yates

Lloyd M. Yates

President and Chief Executive Officer

Date: February 11, 2026

**Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Shawn Anderson, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Shawn Anderson

Shawn Anderson
Executive Vice President and Chief Financial Officer

Date: February 11, 2026

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2025

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM _____ TO _____

Commission file number	Registrant, State or Other Jurisdiction of Incorporation or Organization Address of Principal Executive Offices, Zip Code and Telephone Number	I.R.S. Employer Identification No.
1-31447	CenterPoint Energy, Inc. (a Texas corporation) 1111 Louisiana Houston, Texas 77002 (713) 207-1111	74-0694415
1-3187	CenterPoint Energy Houston Electric, LLC (a Texas limited liability company) 1111 Louisiana Houston, Texas 77002 (713) 207-1111	22-3865106
1-13265	CenterPoint Energy Resources Corp. (a Delaware corporation) 1111 Louisiana Houston, Texas 77002 (713) 207-1111	76-0511406

<u>Registrant</u>	<u>Securities registered pursuant to Section 12(b) of the Act:</u> <u>Title of each class</u>	<u>Trading symbol(s)</u>	<u>Name of each exchange on which registered</u>
CenterPoint Energy, Inc.	Common Stock, \$0.01 par value	CNP	New York Stock Exchange NYSE Texas
CenterPoint Energy Houston Electric, LLC	6.95% General Mortgage Bonds due 2033	n/a	New York Stock Exchange
CenterPoint Energy Resources Corp.	6.625% Senior Notes due 2037	n/a	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

CenterPoint Energy, Inc.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

CenterPoint Energy, Inc.	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
CenterPoint Energy Resources Corp.	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

CenterPoint Energy, Inc.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

CenterPoint Energy, Inc.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
CenterPoint Energy, Inc.	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Act.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

CenterPoint Energy, Inc.	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	<input type="checkbox"/>

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

CenterPoint Energy, Inc.	<input type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	<input type="checkbox"/>
CenterPoint Energy Resources Corp.	<input type="checkbox"/>

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

CenterPoint Energy, Inc.	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
CenterPoint Energy Houston Electric, LLC	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
CenterPoint Energy Resources Corp.	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>

The aggregate market values of the voting stock held by non-affiliates of the Registrants as of June 30, 2025 are as follows:

CenterPoint Energy, Inc. (using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to Securities Exchange Act of 1934 and excluding shares held by directors and executive officers)	\$23,867,105,630
CenterPoint Energy Houston Electric, LLC	None
CenterPoint Energy Resources Corp.	None

Indicate the number of shares outstanding of each of the issuers' classes of common stock as of February 13, 2026:

CenterPoint Energy, Inc.	652,871,584 shares of common stock outstanding, excluding 166 shares held as treasury stock
CenterPoint Energy Houston Electric, LLC	1,000 common shares outstanding, all held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy, Inc.
CenterPoint Energy Resources Corp.	1,000 shares of common stock outstanding, all held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. meet the conditions set forth in general instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2026 Annual Meeting of Shareholders of CenterPoint Energy, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2025, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

GLOSSARY

AFSI	Adjusted financial statement income
AFUDC	Allowance for funds used during construction
AI	Artificial intelligence
ALJ	Administrative Law Judge
AMAs	Asset Management Agreements
AMS	Advanced Metering System
Arevon	Arevon Energy, Inc., which was formed through the combination of Capital Dynamics, Inc.'s U.S. Clean Energy Infrastructure business unit and Arevon Asset Management
ARO	Asset retirement obligation
ARP	Alternative revenue program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
AT&T Common	AT&T Inc. common stock
ATM Forward Purchasers	Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., Goldman Sachs & Co. LLC, JPMorgan Chase Bank, National Association, Mizuho Markets Americas LLC, MUFG Securities EMEA plc and Royal Bank of Canada
ATM Forward Sellers	BofA Securities, Inc. Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC
ATM Managers	BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC
Bcf	Billion cubic feet
Board	CenterPoint Energy's Board of Directors
Bond Companies	Transition Bond Company IV, Restoration Bond Company II and Restoration Bond Company III, each a consolidated VIE that is a wholly-owned, bankruptcy-remote, special purpose entity formed solely for the purpose of securitizing transition property or system restoration property through the issuance of transition bonds or system restoration bonds
BTA	Build Transfer Agreement
CAMT	Corporate Alternative Minimum Tax
CARES Act	Coronavirus Aid, Relief, and Economic Security Act
CCN	Certificate of Convenience and Necessity
CCR	Coal Combustion Residuals
CCR Rule	Final rule published by the EPA in 2015 to regulate coal ash as non-hazardous material under the RCRA
CECA	Clean Energy Cost Adjustment
CEIP	CenterPoint Energy Intrastate Pipelines, LLC, a wholly-owned subsidiary of CERC Corp.
CenterPoint Energy	CenterPoint Energy, Inc., and its subsidiaries
CenterPoint Energy Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among CenterPoint Energy, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, the financial institutions as bank parties thereto and the other parties thereto.
CenterPoint Energy Extension Agreement	Extension Agreement to the CenterPoint Energy Credit Agreement, dated January 29, 2025, by and among CenterPoint Energy, JPMorgan Chase Bank, N.A., as administrative agent, and the banks party thereto
CEOH	Vectren Energy Delivery of Ohio, LLC, doing business as CenterPoint Energy Ohio, which converted its corporate structure from Vectren Energy Delivery of Ohio, Inc. to an Ohio limited liability company on June 13, 2022, formerly a wholly-owned subsidiary of Vectren, acquired by CERC on June 30, 2022
CEP	Capital Expenditure Program
CERC	CERC Corp., together with its subsidiaries
CERC Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among CERC, as borrower, Wells Fargo Bank, National Association, as administrative agent, the financial institutions as bank parties thereto and the other parties thereto
CERC Extension Agreement	Extension Agreement to the CERC Credit Agreement, dated January 29, 2025, by and among CERC, Wells Fargo Bank, National Association, as administrative agent, and the banks party thereto
CERC Corp.	CenterPoint Energy Resources Corp.

GLOSSARY

<i>CERCLA</i>	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
<i>Change in Control Plan</i>	CenterPoint Energy Change in Control Plan (as amended and restated effective May 1, 2017)
<i>Charter Common</i>	Charter Communications, Inc. common stock
<i>CIP</i>	Conservation Improvement Program
<i>Code</i>	The Internal Revenue Code of 1986, as amended
<i>CODM</i>	Chief Operating Decision Maker
<i>Common Stock</i>	CenterPoint Energy, Inc. common stock, par value \$0.01 per share
<i>Convertible Notes</i>	CenterPoint Energy's 4.25% Convertible Senior Notes due 2026
<i>Convertible Notes Indenture</i>	Indenture dated as of August 4, 2023 by and between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee, as supplemented
<i>COVID-19</i>	Novel coronavirus disease 2019, and any mutations or variants thereof, and related global outbreak that was subsequently declared a pandemic by the World Health Organization
<i>CPCN</i>	Certificate of public convenience and necessity
<i>CPS Energy</i>	City Public Service Board of San Antonio, Texas
<i>Credit Agreements</i>	The CenterPoint Energy Credit Agreement, Houston Electric Credit Agreement, CERC Credit Agreement and SIGECO Credit Agreement
<i>CSIA</i>	Compliance and System Improvement Adjustment
<i>DCRF</i>	Distribution Cost Recovery Factor
<i>DOC</i>	U.S. Department of Commerce
<i>DOT</i>	U.S. Department of Transportation
<i>DRR</i>	Distribution Replacement Rider
<i>DSMA</i>	Demand Side Management Adjustment
<i>Dth</i>	Dekatherms
<i>ECA</i>	Environmental Cost Adjustment
<i>EDF Renewables</i>	EDF Renewables Development, Inc.
<i>EDIT</i>	Excess deferred income taxes
<i>EECR</i>	Energy Efficiency Cost Recovery
<i>EECRF</i>	Energy Efficiency Cost Recovery Factor
<i>EEFC</i>	Energy Efficiency Funding Component
<i>EEFR</i>	Energy Efficiency Funding Rider
<i>ELG</i>	Effluent Limitation Guidelines
<i>EIA</i>	U.S. Energy Information Administration
<i>Energy Systems Group</i>	Energy Systems Group, LLC, previously a wholly-owned subsidiary of Vectren
<i>EPA</i>	Environmental Protection Agency
<i>EPC</i>	Engineering, Procurement and Construction
<i>Equity Distribution Agreement</i>	Equity Distribution Agreement, dated as of January 10, 2024, by and between CenterPoint Energy, the ATM Managers, the ATM Forward Purchasers and the ATM Forward Sellers
<i>Equity Purchase Agreement</i>	Equity Purchase Agreement, dated as of May 21, 2023, by and between Vectren Energy Services and ESG Holdings Group
<i>ERCOT</i>	Electric Reliability Council of Texas
<i>ERCOT ISO</i>	ERCOT Independent System Operator
<i>ERISA</i>	Employee Retirement Income Security Act of 1974
<i>ERO</i>	Electric Reliability Organization
<i>ESG Holdings Group</i>	ESG Holdings Group, LLC a Delaware limited liability company, and an affiliate of Oaktree Capital Management
<i>Exchange Act</i>	The Securities Exchange Act of 1934, as amended
<i>Extension Agreements</i>	The CenterPoint Energy Extension Agreement, Houston Electric Extension Agreement, CERC Extension Agreement and SIGECO Extension Agreement
<i>FAC</i>	Fuel Adjustment Clause
<i>FASB</i>	Financial Accounting Standards Board

GLOSSARY

February 2021 Winter Storm Event	The extreme and unprecedented winter weather event in February 2021 (also known as Winter Storm Uri) resulting in electricity generation supply shortages, including in Texas, and natural gas supply shortages and increased wholesale prices of natural gas in the United States, primarily due to prolonged freezing temperatures.
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
Form 10-K	Annual Report on Form 10-K
FPA	Federal Power Act
GAAP	Generally Accepted Accounting Principles
General Mortgage	General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee, as supplemented from time to time
GHG	Greenhouse gases
GRIP	Gas Reliability Infrastructure Program
GWh	Gigawatt-hours
HLPSA	Hazardous Liquid Pipeline Safety Act of 1979
Houston Electric	CenterPoint Energy Houston Electric, LLC and its subsidiaries
Houston Electric Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among Houston Electric, as borrower, Mizuho Bank, Ltd., as administrative agent, the financial institutions as bank parties thereto and the other parties thereto
Houston Electric Extension Agreement	Extension Agreement to the Houston Electric Credit Agreement, dated January 29, 2025, by and among Houston Electric, Mizuho Bank, Ltd., as administrative agent, and the banks party thereto
Human Capital and Compensation Committee	Human Capital and Compensation Committee of the Board
Hurricane Beryl	The powerful and destructive storm that made landfall in Texas on July 8, 2024 and caused widespread damage to Houston Electric's electric delivery system
HVAC	Heating, ventilation and air conditioning
IAS	International Accounting Standards
IBEW	International Brotherhood of Electrical Workers
ICPA	Inter-Company Power Agreement
IDEM	Indiana Department of Environmental Management
IG	Intelligent Grid
Indiana Electric	Operations of SIGECO's electric transmission and distribution services, and includes its power generating and wholesale power operations
Indiana Gas	Indiana Gas Company, Inc., a wholly-owned subsidiary of CERC Corp.
Indiana North	Gas operations of Indiana Gas
Indiana South	Gas operations of SIGECO
Indiana Utilities	Indiana Electric, Indiana North and Indiana South, collectively
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
Junior Subordinated Notes	Junior Subordinated Series A Notes, Junior Subordinated Series B Notes and Junior Subordinated Series C Notes
Junior Subordinated Notes Indenture	Junior Subordinated Indenture, dated as of August 14, 2024, between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee, as supplemented
Junior Subordinated Series A Notes	7.000% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series A, due 2055
Junior Subordinated Series B Notes	6.850% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series B, due 2055
Junior Subordinated Series C Notes	6.700% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series C, due 2055
kV	Kilovolt
LAMS Asset Purchase Agreement	Asset Purchase Agreement, dated as of February 19, 2024, by and among CERC Corp. and the LAMS Buyers

GLOSSARY

LAMS Buyers	Delta North Louisiana Gas Company, LLC, a Delaware limited liability company, Delta South Louisiana Gas Company, LLC, a Delaware limited liability company, Delta Mississippi Gas Company, LLC, a Delaware limited liability company, and Delta Energy Resources, LLC, a Delaware limited liability company
LDC	Local Distribution Company
LNG	Liquefied natural gas
Load Shed	Curtailling the amount of electricity a TDU can transmit and distribute to its customers
LTIPs	Long-term incentive plans
M&DOT	Mortgage and Deed of Trust, dated November 1, 1944, between Houston Lighting and Power Company and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented
May 2024 Storm Events	The sudden and destructive severe weather events in May 2024 that included hurricane-like winds and tornadoes and resulted in widespread damage to Houston Electric's electric delivery system
MCRA	MISO Cost and Revenue Adjustment
MDL	Multi-district litigation
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator
MMBtu	One million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Service, Inc.
MPUC	Minnesota Public Utilities Commission
Mva	Megavolt amperes
MW	Megawatts
NAV	Net asset value
NECA	National Electrical Contractors Association
NERC	North American Electric Reliability Corporation
Netflix	Netflix, Inc.
NFGC	National Fuel Gas Company, a New Jersey corporation
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968
NOLs	Net operating losses
NRG	NRG Energy, Inc.
NYSE	New York Stock Exchange
OBBBA	Tax reform legislation informally known as the One Big Beautiful Bill Act
Ohio Securities Purchase Agreement	Securities Purchase Agreement, dated as of October 20, 2025, by and between CERC Corp. and NFGC
OPEIU	Office & Professional Employees International Union
Oriden	Oriden LLC
Origis	Origis Energy USA Inc.
OUCC	Indiana Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020
Posey Solar	Posey Solar, LLC, a Delaware limited liability company
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PTCs	Production Tax Credits
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas

GLOSSARY

Railroad Commission	Railroad Commission of Texas
RCRA	Resource Conservation and Recovery Act of 1976
Registrant	Each of CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp.
Reliant Energy	Reliant Energy, Incorporated
REP	Retail electric provider
Restoration Bond Company II	CenterPoint Energy Restoration Bond Company II, LLC, a wholly-owned subsidiary of Houston Electric
Restoration Bond Company II Securitization Bonds	Restoration Bond Company II's Series 2025-A Senior Secured System Restoration Bonds
Restoration Bond Company III	CenterPoint Energy Restoration Bond Company III, LLC, a wholly-owned subsidiary of Houston Electric
Restructuring	CERC Corp.'s common control acquisition of Indiana Gas and CEOH from VUH on June 30, 2022
ROE	Return on equity
ROU	Right of use
S&P	S&P Global Ratings, a division of S&P Global Inc.
Scope 1 emissions	Direct source of GHG emissions from a company's operations
Scope 2 emissions	Indirect source of GHG emissions from a company's energy usage
Scope 3 emissions	Indirect source of GHG emissions from a company's end-users
SEC	Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Securitization Bonds	Transition and system restoration bonds issued by the Bond Companies and SIGECO Securitization Bonds issued by the SIGECO Securitization Subsidiary
Seller Note Agreement	Seller Note Agreement by and between CERC Corp. and NFGC to be entered into at the closing of the proposed sale of all of the issued and outstanding equity interests in CEOH to NFGC contemplated by the Ohio Securities Purchase Agreement
Series A Preferred Stock	CenterPoint Energy's previously outstanding Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Stock, par value \$0.01 per share, with a liquidation preference of \$1,000 per share
Series 2025B Bonds	SIGECO's 5.09% First Mortgage Bonds, Series 2025B, Tranche A due 2031 and its 5.52% First Mortgage Bonds, Series 2025B, Tranche B due 2035
Series 2025C Bonds	SIGECO's 5.77% First Mortgage Bonds, Series 2025C, Tranche A due 2040 and its 6.18% First Mortgage Bonds, Series 2025C, Tranche B due 2055
SIGECO	Southern Indiana Gas and Electric Company, a wholly-owned subsidiary of Vectren
SIGECO Credit Agreement	Credit Agreement, dated as of December 6, 2022, by and among SIGECO, as borrower, Wells Fargo Bank, National Association, as administrative agent, the financial institutions as banks parties thereto and the other parties thereto
SIGECO Extension Agreement	Extension Agreement to the SIGECO Credit Agreement, dated as of January 29, 2025, by and among SIGECO, Wells Fargo Bank, National Association, as administrative agent and the banks party thereto
SIGECO Securitization Bonds	SIGECO Securitization Subsidiary's Series 2023-A Senior Secured Securitization Bonds
SIGECO Securitization Subsidiary	SIGECO Securitization I, LLC, a direct, wholly-owned subsidiary of SIGECO
SOFR	Secured Overnight Financing Rate
SRC	Sales Reconciliation Component
SRP	The transmission and distribution system resiliency plan filed by Houston Electric with the PUCT on January 31, 2025, which proposes investing approximately \$5.75 billion over a three-year period for transmission and distribution infrastructure, information technology and cybersecurity assets and event response capability
TBD	To be determined
TCA	Texas Consumer Association
TCJA	Tax reform legislation informally called the Tax Cuts and Jobs Act of 2017
TCOS	Transmission Cost of Service
TCRF	Transmission Cost Recovery Factor
TDSIC	Transmission, Distribution and Storage System Improvement Charge
TDU	Transmission and distribution utility

GLOSSARY

TEEEF	Assets leased or costs incurred as “temporary emergency electric energy facilities” under Section 39.918 of the Public Utility Regulatory Act, also referred to as temporary generation
TEEEF Rule	Texas Administrative Code, Title 16, Section 25.56, which became effective January 8, 2025 and was further amended on February 6, 2025
Texas RE	Texas Reliability Entity
Transition Bond Company IV	CenterPoint Energy Transition Bond Company IV, LLC, a wholly-owned subsidiary of Houston Electric
TSA	Transportation Security Administration
USW	United Steelworkers Union
UWUA	Utility Workers Union of America
Utility Holding	Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy
Vectren	Vectren, LLC, which converted its corporate structure from Vectren Corporation to a limited liability company on June 30, 2022, a wholly-owned subsidiary of CenterPoint Energy as of February 1, 2019, and, after the Restructuring, is held indirectly by CenterPoint Energy through Vectren Affiliated Utilities, Inc.
Vectren Energy Services	Vectren Energy Services Corporation, an Indiana corporation and a wholly-owned subsidiary of CenterPoint Energy
VIE	Variable interest entity
Vistra Energy Corp.	Texas-based energy company focused on the competitive energy and power generation markets.
VRP	Voluntary Remediation Program
WBD	Warner Bros. Discovery, Inc.
WBD Common	Warner Bros. Discovery, Inc. Series A common stock
ZENS	2.0% Zero-Premium Exchangeable Subordinated Notes due 2029
ZENS-Related Securities	As of December 31, 2025 and December 31, 2024, consisted of AT&T Common, Charter Common and WBD Common
2024 Form 10-K	Annual Report on Form 10-K for the fiscal year ended December 31, 2024
2026 Convertible Notes	CenterPoint Energy’s 4.25% Convertible Senior Notes due 2026
2026 Convertible Notes Indenture	Indenture dated as of August 4, 2023 by and between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee, as supplemented
2028 Convertible Notes	CenterPoint Energy’s 3.00% Convertible Senior Notes due 2028
2028 Convertible Notes Indenture	Indenture, dated as of July 31, 2025, by and between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time the Registrants make statements concerning their expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify forward-looking statements by the words “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “objective,” “plan,” “potential,” “predict,” “projection,” “should,” “target,” “will” or other similar words.

The Registrants have based their forward-looking statements on management’s beliefs and assumptions based on information reasonably available to management at the time the statements are made. The Registrants caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, the Registrants cannot assure you that actual results will not differ materially from those expressed or implied by the Registrants’ forward-looking statements. In this Form 10-K, unless context requires otherwise, the terms “our,” “we” and “us” are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric, CERC and SIGECO.

Some of the factors that could cause actual results to differ from those expressed or implied by the Registrants’ forward-looking statements are described under “Risk Factors” in Item 1A and “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings” and “— Liquidity and Capital Resources — Other Matters — Other Factors That Could Affect Cash Requirements” in Item 7 of Part II of this report, which discussions are incorporated herein by reference.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, other than as required under applicable securities laws, the Registrants undertake no obligation to update or revise any forward-looking statements.

SUMMARY OF RISK FACTORS

An investment in CenterPoint Energy’s securities involves a significant degree of risk. Below is a summary of certain risk factors to consider in evaluating CenterPoint Energy as well as its Common Stock. However, this list is not exhaustive. Before investing in CenterPoint Energy, carefully consider the risk factors discussed or referenced below and in Item 1A. “Risk Factors” of this combined report on Form 10-K. If any of the risks discussed below and in Item 1A. “Risk Factors” were actually to occur, CenterPoint Energy’s, Houston Electric’s and CERC’s business, financial condition, results of operations or cash flows could be adversely affected. In that case, CenterPoint Energy might not be able to pay dividends on its Common Stock, or the trading price of its Common Stock could decline.

Risk Factors Affecting Operations

Electric Transmission, Distribution and Generation (CenterPoint Energy and Houston Electric)

- Disruptions at third-party or Indiana Electric’s power generation facilities, generation inadequacy, directives issued by regulatory authorities or other matters could cause interruptions in Houston Electric’s and Indiana Electric’s ability to provide transmission and distribution services and Houston Electric and Indiana Electric may not be able to promptly respond, repair and restart their facilities, which could adversely affect their businesses, financial condition, results of operations and cash flows.
- Indiana Electric’s execution of its generation transition plan is subject to various risks, including timely recovery of capital investments and increased costs and risks related to the timing and cost of development and/or construction of new generation facilities.
- Houston Electric’s receivables are primarily concentrated in a small number of REPs, and any delay or default in payments of these receivables could adversely affect Houston Electric’s business, financial condition, results of operations and cash flows.
- Houston Electric’s use of TEEEF is subject to various risks, potential performance issues and allegations about Houston Electric’s procurement and deployment of the resources (including the planning, execution and effectiveness of the same), regulatory and environmental requirements, and timely recovery of capital.

Natural Gas (CenterPoint Energy and CERC)

- Access to natural gas supplies and pipeline transmission and storage capacity are essential components of reliable service for our natural gas business customers.
- We are subject to fluctuations in natural gas prices, which could affect the ability of our suppliers and customers to meet their obligations or may impact our operations, which could adversely affect our business, financial condition, results of operations and cash flows.
- Our natural gas businesses must compete with alternate energy sources, which could result in less natural gas delivered and have an adverse impact on our businesses, financial condition, results of operations and cash flows.

Risk Factors Affecting Regulatory, Environmental and Legal Risks

- Rate regulation of the Registrants' electric and natural gas businesses may delay or deny their ability to earn an expected return and fully and timely recover their costs.
- Our successful execution and completion of capital projects and programs, including those within our 10-year capital plan, are subject to substantial risks, and our business, financial condition, results of operations and cash flows could be materially affected should such efforts not be executed and completed as planned.
- We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could negatively affect our financial results.
- Negative opinions of CenterPoint Energy from customers, investors, legislators, regulators, creditors, rating agencies and other stakeholders relating to actual or perceived system reliability and safety, the speed of our response to service interruptions, rates and customer affordability, our ability to successfully execute our capital plan, media coverage and actions by third parties, could harm our reputation and have an adverse impact on our business, financial condition, results of operations and cash flows.
- We are subject to operational and financial risks and liabilities arising from environmental laws and regulations, including regulation of CCR, federal and state climate change legislation and regulation and certain local initiatives that seek to limit fossil fuel usage.
- CenterPoint Energy is subject to operational and financial risks and liabilities associated with its sustainability and related activities, including the implementation of and efforts to achieve its energy transition goals.
- We are subject to extensive regulation, which could result in higher costs for system improvements, as well as fines or other sanctions.

Risk Factors Affecting Financial, Economic and Market Risks

- Disruptions to the global supply chain, inflation, labor shortages and scarcity of certain materials may impact our operations, which could have an adverse impact on our ability to execute our capital plan and on our business, financial condition, results of operations and cash flows.
- If we are unable to arrange future financings on acceptable terms, our ability to finance our capital expenditures and operations or refinance outstanding indebtedness could be limited.
- CenterPoint Energy is a holding company that derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. As a result, CenterPoint Energy depends on the performance of and distributions from its subsidiaries to meet its payment obligations and to pay dividends on its common stock, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.
- If CenterPoint Energy redeems the ZENS prior to their maturity in 2029, its ultimate tax liability and redemption payments may result in significant cash payments, which would adversely impact its cash flows and liquidity. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity.

Risk Factors Affecting Safety and Security Risks

- The Registrants' businesses have safety risks.
- Cyberattacks, physical security breaches, acts of terrorism or other disruptions could adversely impact our business, financial condition, results of operations and cash flows.
- We may not be successful in our adoption, development and deployment of AI, which could adversely affect our business, reputation or financial results.

General and Other Risks

- Our revenues and results of operations are seasonal.
- Severe weather events, natural disasters and other climate-related impacts could adversely impact our businesses, financial condition, results of operations and cash flows.
- We are exposed to risks related to changes in demand and energy consumption that could adversely impact our business, financial condition, results of operations and cash flows.
- Our business, financial condition, results of operations and cash flows may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.
- Aging infrastructure may lead to increased costs and disruptions in operations that could negatively impact our financial results.
- Our businesses will continue to have to adapt to, implement and integrate technological change and may not be successful implementing such technological change as designed or may have to make significant investments to adapt to and integrate technological change.

PART I

Item 1. *Business*

This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. Information contained herein relating to any individual Registrant is filed by such Registrant solely on its own behalf. No Registrant makes any representation as to information relating to the other Registrants or the subsidiaries of CenterPoint Energy, Inc. other than itself or its subsidiaries. Except as discussed in Note 12 to the consolidated financial statements, no Registrant has an obligation in respect of any other Registrant's debt securities, and holders of such debt securities should not consider the financial resources or results of operations of any Registrant other than the obligor in making a decision with respect to such securities.

The discussion of CenterPoint Energy's consolidated financial information includes the financial results of Houston Electric and CERC. Where appropriate, information relating to a specific Registrant has been segregated and labeled as such. Unless the context indicates otherwise, specific references to Houston Electric and CERC also pertain to CenterPoint Energy. In this combined Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric and CERC, unless otherwise stated.

OUR BUSINESS

Overview

CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems.

As of December 31, 2025, CenterPoint Energy's indirect, wholly-owned operating subsidiaries included:

- Houston Electric, which provides electric transmission service to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston.
- CERC Corp., which (i) directly owns and operates natural gas distribution systems in Minnesota and Texas, (ii) indirectly, through Indiana Gas and CEOH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; and
- SIGECO, which provides energy delivery services to electric and natural gas customers located in and near Evansville in southwestern Indiana and owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market.

As of December 31, 2025, CenterPoint Energy's reportable segments were Electric, Natural Gas and Corporate and Other. Houston Electric and CERC each consist of one reportable segment. For a description of CenterPoint Energy's reportable segments, see Note 16. For a discussion of net income by segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations by Reportable Segment" in Item 7 of Part II of this report.

On March 7, 2025, SIGECO acquired 100% of the equity interests in Posey Solar, which was constructing a 191 MW solar array in Posey County, Indiana, for approximately \$357 million. On March 31, 2025, CenterPoint Energy, through its subsidiary CERC Corp., completed the sale of its Louisiana and Mississippi natural gas LDC businesses for approximately \$1.2 billion. On October 20, 2025, CenterPoint Energy, through its subsidiary CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH for total consideration of approximately \$2.62 billion, which is comprised of the following: (i) \$1.42 billion in cash payable to CERC Corp. upon closing of the transaction, subject to adjustments as set forth in the Ohio Securities Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing of the transaction; and (ii) a 364-day seller promissory note, in the original principal amount of \$1.2 billion, to be issued by NFGC at the closing of the transaction and payable to CERC Corp. as provided by the terms and conditions of the Seller Note Agreement. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

The Registrants' principal executive offices are located at 1111 Louisiana Street, Houston, Texas 77002 (telephone number: 713-207-1111).

We make available free of charge on CenterPoint Energy's internet website, <http://www.centerpointenergy.com>, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at <http://www.sec.gov>. Additionally, we make available free of charge on CenterPoint Energy's internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;
- our Ethics and Compliance Code;
- our Supplier Code of Conduct;
- our Corporate Governance Guidelines; and
- the charters of the Audit, Corporate Governance and Nominating, Human Capital and Compensation, and Safety and Operations committees of our Board.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our internet website within five business days of such change or waiver and maintained for at least 12 months or timely reported on Item 5.05 of Form 8-K.

Investors should also note that we announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, we may use the investor relations section of our internet website to communicate with our investors. It is possible that the financial and other information posted there could be deemed to be material information. Except to the extent explicitly stated herein, documents and information on our internet website are not incorporated by reference herein.

Electric (CenterPoint Energy)

The Electric reportable segment is comprised of Houston Electric and Indiana Electric.

For information regarding the properties of the Electric reportable segment, see "Properties — Electric (CenterPoint Energy and Houston Electric)" in Item 2 of this report, which information is incorporated herein by reference.

Houston Electric (CenterPoint Energy and Houston Electric)

Houston Electric is a transmission and distribution electric utility that operates wholly within the state of Texas. Houston Electric does not make direct retail or wholesale sales of electric energy or own or operate any power generating facilities other than TEEEF.

Electric Transmission

On behalf of REPs, Houston Electric delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power at or above 69 kV in locations throughout Houston Electric's certificated service territory. Houston Electric constructs and maintains transmission facilities and provides transmission services under tariffs approved by the PUCT.

Electric Distribution

Houston Electric's distribution network receives electricity from the transmission grid through power distribution substations and delivers electricity for REPs in its certificated service area by carrying lower-voltage power from the substation to the retail electric customer through distribution feeders. Houston Electric's operations include construction and maintenance of distribution facilities, metering services, outage response services and call center operations. Houston Electric provides distribution services under tariffs approved by the PUCT. PUCT rules and market protocols govern the commercial operations of distribution companies and other market participants. Rates for these services are established pursuant to rate proceedings conducted before municipalities that have original jurisdiction and the PUCT.

TEEEF

As allowed by a law enacted by the Texas legislature after the February 2021 Winter Storm Event and amended in 2023, Houston Electric has entered into contractual arrangements to facilitate access to TEEEF units, both on a long-term basis and, to a limited extent, on a month-to-month basis, that can aid in restoring power to customers during certain significant power outages that are impacting its distribution system. In June 2025, Houston Electric entered into definitive documentation (the "ERCOT Transaction"), subject to PUCT approval, with relevant parties to release its 15 large 27 MW to 32 MW TEEEF units to the San Antonio area until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction, during which Houston Electric will not receive revenue or profit from ERCOT and will also not charge Houston-area customers for these TEEEF units while they are in the San Antonio area serving ERCOT. In November 2025, Houston Electric proposed to release its five medium (5.7 MW) TEEEF units and to remove the associated lease costs from its rates effective January 1, 2026. On February 13, 2026, Houston Electric requested continued abatement until February 27, 2026 due to continued settlement discussions. As of December 31, 2025, Houston Electric leased 519 MW of TEEEF on a long-term basis. For more information, see Note 7 and Note 19 to the consolidated financial statements.

Bond Companies

Houston Electric has VIEs, including Transition Bond Company IV and Restoration Bond Company II, which are consolidated. The consolidated VIEs are wholly-owned, bankruptcy-remote, special purpose entities that were formed solely for the purpose of securitizing transition property or system restoration property through the issuance of transition bonds or system restoration bonds, and conducting activities incidental thereto. The Securitization Bonds are repaid through charges imposed on customers in Houston Electric's service territory. On October 15, 2024, Transition Bond Company IV repaid in full its last outstanding transition bonds at maturity. For further discussion of the Securitization Bonds and the outstanding balances as of December 31, 2025 and 2024, see Note 12 to the consolidated financial statements.

Customers

Houston Electric serves nearly all of the Houston/Galveston metropolitan area near the Texas Gulf Coast. Houston Electric's customers consist of REPs, which sell electricity to metered customers in Houston Electric's certificated service area, and municipalities, electric cooperatives and other distribution companies located outside Houston Electric's certificated service area. Each REP is licensed by, and must meet minimum creditworthiness criteria established by, the PUCT. Houston Electric does not have long-term contracts with any of its customers, but rather operates using a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day. For information regarding Houston Electric's major customers, see Note 16 to the consolidated financial statements.

The table below reflects the number of REPs and metered customers in Houston Electric's service area as of December 31, 2025:

	REPs	Residential	Commercial/ Industrial	Total Customers
Texas Gulf Coast	67	2,544,880	314,433	2,859,313

Competition

There are no other electric transmission and distribution utilities in Houston Electric's service area. For another provider of transmission and distribution services to provide such services in Houston Electric's territory, it would be required to obtain a CCN from the PUCT and, depending on the location of the facilities, may also be required to obtain franchises from one or more municipalities. Houston Electric is not aware of any other party intending to enter this business in its service area at this time. Distributed generation (i.e., power generation located at or near the point of consumption) could result in a reduction of demand for Houston Electric's distribution services but has not been a significant factor to date.

Seasonality

Houston Electric's revenues are primarily derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of that REP. Houston Electric's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months when more electricity is used for cooling purposes.

Franchises

Houston Electric holds non-exclusive franchises from certain incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give Houston Electric the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 40 years.

Indiana Electric (CenterPoint Energy)

Indiana Electric consists of SIGECO's electric transmission and distribution services, including its electric generation assets and wholesale power operations. The table below reflects the number of metered customers to whom Indiana Electric supplied electric service as of December 31, 2025:

	Residential	Commercial/Industrial	Total Customers
Southwestern Indiana	134,695	19,707	154,402

System Load

Total load and the related reserve margin at the time of the system summer peak on June 25, 2025 is presented below in MW, except for reserve margin at peak:

	2025
Total load at peak	1,073
Generating capability	1,071
Purchase supply (effective capacity) (1)	263
Interruptible contracts & direct load control	14
Total power supply capacity	1,348
Reserve margin at peak	26 %

(1) Total reflects long-term and short-term capacity contracts secured to meet MISO planning requirements.

The winter peak load for the 2024-2025 season of approximately 849 MW occurred on January 21, 2025.

Solar and Wind

Indiana Electric has entered into various PPAs to purchase solar power and wind power to meet its future generation needs as reported in the table below:

Power Type	Counterparty	Location	Date in Service/Expected Date in Service	Capacity (MW)	Term (in Years)
Wind	NextEra Energy, Inc.	Tama County, Iowa	2025	170	27
Solar	Origis	Knox County, Indiana	2026	150	20
Wind	NextEra Energy, Inc.	Knox County, Illinois	2026	147	25
				467	

For further information about Indiana Electric's solar power and wind power activities, see "Item 2. Properties" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Coal Purchases

Coal for coal-fired generating stations has been supplied from operators of nearby coal mines as there are substantial coal reserves in the southern Indiana area. Major suppliers are those that account for greater than 10% of Indiana Electric's coal purchases. For the year ended December 31, 2025, Sunrise LLC accounted for 100% of Indiana Electric's coal purchases.

The table below presents information related to coal purchases during the year ended December 31, 2025 and coal inventory as of December 31, 2025:

	(In tons, except average cost per ton)
Coal purchased for generating electricity	643,030
Coal inventory as of December 31, 2025	422,503
Average cost of coal per ton	\$68.04

Firm Purchase Supply

Indiana Electric enters into long-term purchase supply agreements to meet its generation needs as disclosed below:

Fuel Type	Provider	Location	Contract Expiration	Capacity (MW)	Purchased in 2025 (in GWh)
Coal	OVEC (1)	Indiana and Ohio	2040	32	203
Wind	Benton County Wind Farm, LLC	Benton County, Indiana	2028	30	81
Wind	Fowler Ridge II Wind Farm, LLC	Benton/Tippecanoe Counties, Indiana	2029	50	129
Wind	Salt Creek Wind, LLC	Tama County, Iowa	2052	170	52
				282	465

(1) As part of its power portfolio, Indiana Electric is a 1.5% shareholder in the OVEC. Based on its participation in the ICPA between OVEC and its shareholder companies, Indiana Electric has the right to 1.5% of OVEC's generating capacity output and shares in 1.5% of the operating expenses and debt obligations of OVEC.

MISO-Related Activity

Indiana Electric is a member of the MISO, a FERC-approved regional transmission organization. The MISO serves the electric transmission needs of much of the Midcontinent region and maintains operational control over Indiana Electric's electric transmission facilities and generation facilities as well as other utilities in the region. Indiana Electric is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing as determined by the MISO market. MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on at least a net hourly position.

MISO-related activity for the year ended December 31, 2025 was as follows:

	In GWh
Net purchases (1)	3,007
Net sales (2)	2

- (1) Represents intervals when purchases from the MISO were in excess of generation sold to the MISO.
(2) Represents intervals when sales to the MISO were in excess of purchases from the MISO.

Interconnections

As of December 31, 2025, Indiana Electric had interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc. and Big Rivers Electric Corporation providing the ability to simultaneously interchange approximately 660 MW during peak load periods. Indiana Electric, as required as a member of the MISO, has turned over operational control of the interchange facilities and its own transmission assets to the MISO. Indiana Electric, in conjunction with the MISO, must operate the bulk electric transmission system in accordance with NERC Reliability Standards. As a result, interchange capability varies based on regional transmission system configuration, generation dispatch, seasonal facility ratings and other factors. Indiana Electric is in compliance with reliability standards promulgated by NERC.

SIGECO Securitization Subsidiary

SIGECO has a VIE, SIGECO Securitization Subsidiary, which is consolidated. This consolidated VIE is a wholly-owned, bankruptcy-remote, special purpose entity that was formed solely for the purpose of facilitating the securitization financing of qualified costs. The obligations of the SIGECO Securitization Bonds are repaid through charges imposed on customers in Indiana Electric's service territory. For further discussion of the SIGECO Securitization Bonds and the outstanding balance as of December 31, 2025, see Note 12 to the consolidated financial statements.

Competition

There are no other electric transmission and distribution utilities in Indiana Electric's service area. Indiana Electric is a vertically integrated utility that owns the generation, transmission, and distribution components of a utility.

For another provider of transmission and distribution services to provide such services in Indiana Electric's territory, it would be required to obtain IURC approval of such service territory. Indiana service territory certificates are exclusive. Distributed generation (i.e., power generation located at or near the point of consumption) could result in reduced demand for Indiana Electric's distribution services but has not been a significant factor to date.

Seasonality

Indiana Electric's revenues are primarily derived from rates that it collects from customers in its service territory based on the amount of electricity it delivers. Indiana Electric's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months when more electricity is used for cooling purposes, and during the cooler months when more electricity is used for heating purposes.

Natural Gas (CenterPoint Energy and CERC)

CenterPoint Energy's and CERC's natural gas distribution businesses engage in regulated intrastate natural gas sales to, and natural gas transportation and storage for, residential, commercial, industrial and transportation customers. CenterPoint Energy's and CERC's natural gas distribution businesses provide permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP. CenterPoint Energy's and CERC's natural gas distribution businesses also provided services in Minnesota consisting of residential appliance repair and maintenance services along with HVAC equipment sales. Additionally, CenterPoint Energy and CERC's natural gas distribution businesses provided home repair protection plans to natural gas customers in Indiana, Ohio and Texas through a third party as of December 31, 2025.

For information regarding the properties of the Natural Gas reportable segment, read "Properties — Natural Gas (CenterPoint Energy and CERC)" in Item 2 of this report, which information is incorporated herein by reference.

On March 31, 2025, CenterPoint Energy, through its subsidiary CERC Corp., completed the sale of its Louisiana and Mississippi natural gas LDC businesses. On October 20, 2025, CenterPoint Energy, through its subsidiary CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH for total consideration of approximately \$2.62 billion, which is comprised of the following: (i) \$1.42 billion in cash payable to CERC Corp. upon closing of the transaction, subject to adjustments as set forth in the Ohio Securities Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing of the transaction; and (ii) a 364-day seller promissory note, in the original principal amount of \$1.2 billion, to be issued by NFGC at the closing of the transaction and payable to CERC Corp. as provided by the terms and conditions of the Seller Note Agreement. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

Customers

The table below reflects the number of CenterPoint Energy's and CERC's natural gas distribution business customers by state as of December 31, 2025:

	Residential	Commercial/ Industrial/Transportation	Total Customers
Indiana (Indiana Gas)	613,299	55,996	669,295
Minnesota	865,667	73,063	938,730
Ohio	312,131	24,711	336,842
Texas	1,843,325	124,730	1,968,055
Total CERC Natural Gas	3,634,422	278,500	3,912,922
Indiana (SIGECO)	105,497	10,666	116,163
Total CenterPoint Energy Natural Gas	3,739,919	289,166	4,029,085

The largest metropolitan areas served in each state were Houston, Texas; Minneapolis, Minnesota; Evansville, Indiana; and Dayton, Ohio.

The table below reflects the percentage of total throughput by customer type for the year ended December 31, 2025:

	CenterPoint Energy	CERC
Residential	34 %	36 %
Commercial/Industrial and Transportation	66 %	64 %
Total Throughput	100 %	100 %

Seasonality

The demand for natural gas sales to residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal and affected by variations in weather conditions. In 2025, approximately 68% and 69% of the total throughput for CenterPoint Energy's and CERC's natural gas distribution businesses, respectively, occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during the colder months.

Supply and Transportation

In 2025, CenterPoint Energy's natural gas distribution businesses purchased virtually all of their natural gas supply pursuant to contracts with remaining terms varying from a few months to three years. Major suppliers are those that account for greater than 10% of CenterPoint Energy's or CERC's annual natural gas supply purchases.

Major suppliers of natural gas for the year ended December 31, 2025 were as follows:

	CenterPoint Energy	CERC
Tenaska Marketing Ventures, LLC	32 %	30 %
Macquarie Energy, LLC	12 %	13 %
BP Energy Company	8 %	8 %
Total of major suppliers	52 %	51 %

Numerous other suppliers provided the remainder of CenterPoint Energy's and CERC's natural gas supply requirements.

CenterPoint Energy's and CERC's natural gas distribution businesses transport their natural gas supplies through various intrastate and interstate pipelines under contracts with remaining terms, including extensions, varying from one to fifteen years. CenterPoint Energy's and CERC's natural gas distribution businesses anticipate that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

CenterPoint Energy's and CERC's natural gas distribution businesses actively engage in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of their state regulatory authorities. These price stabilization activities include use of storage gas and contractually establishing structured prices (e.g., fixed price, costless

collars and caps) with CenterPoint Energy's and CERC's natural gas distribution business' physical gas suppliers. Their gas supply plans generally call for 50–70% of normal winter supplies to be stabilized in some fashion.

The regulations of the states in which CenterPoint Energy's and CERC's natural gas distribution businesses operate allow them to pass through changes in the cost of natural gas, including savings and costs of financial derivatives associated with the index-priced physical supply, to their customers under purchased gas adjustment provisions in their tariffs. Depending upon the jurisdiction, the purchased gas adjustment factors are updated periodically, ranging from monthly to semi-annually. The changes in the cost of gas billed to customers are subject to review by the applicable regulatory bodies.

CenterPoint Energy's and CERC's natural gas distribution businesses use various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. CenterPoint Energy's and CERC's natural gas distribution businesses may also supplement contracted supplies and storage from time to time with stored LNG and propane-air plant production.

On an ongoing basis, CenterPoint Energy's and CERC's natural gas distribution businesses enter into contracts to provide sufficient supplies and pipeline capacity to meet their customer requirements. However, it is possible for limited service disruptions to occur from time to time due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time, or prices may increase rapidly in response to temporary supply constraints or other factors.

CenterPoint Energy's and CERC's natural gas distribution businesses continue to utilize AMAs associated with their utility distribution service in Indiana, Minnesota and Texas. Generally, AMAs are contracts between CenterPoint Energy's and CERC's natural gas distribution businesses and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, CenterPoint Energy's and CERC's natural gas distribution businesses agree to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for CenterPoint Energy's and CERC's natural gas distribution businesses and to use the released capacity for other purposes when it is not needed for CenterPoint Energy's and CERC's natural gas distribution businesses. CenterPoint Energy's and CERC's natural gas distribution businesses may receive compensation from the asset manager through payments made over the life of the AMAs. CenterPoint Energy's and CERC's natural gas distribution businesses have an obligation to purchase their winter storage requirements that have been released to the asset manager under these AMAs. The AMAs have varying terms, the longest of which expires in 2029. Pursuant to the provisions of the agreements, CenterPoint Energy's and CERC's natural gas distribution businesses either sell natural gas to the asset manager and agree to repurchase an equivalent amount of natural gas throughout the year at the same cost, or simply purchases its full natural gas requirements at each delivery point from the asset manager. Each of CenterPoint Energy and CERC had no amounts outstanding under these AMAs as of December 31, 2025 and 2024.

Competition

CenterPoint Energy's and CERC's natural gas distribution businesses compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other gas distributors and marketers also compete directly for gas sales to end users. In addition, as a result of federal regulations affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass CenterPoint Energy's and CERC's natural gas distribution business' facilities and market, sell and/or transport natural gas directly to commercial and industrial customers.

Franchises

In almost all communities in which CenterPoint Energy's and CERC's natural gas distribution businesses provide natural gas distribution services, they operate under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 10 to 30 years. CenterPoint Energy's and CERC's natural gas distribution businesses expect to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Corporate and Other (CenterPoint Energy)

CenterPoint Energy's Corporate and Other reportable segment consists of corporate support operations that support CenterPoint Energy's business operations and also includes office buildings and other real estate used for business operations. CenterPoint Energy's Corporate and Other reportable segment also consisted of energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group. For additional information on the sale of Energy Systems Group, see Note 4 to the consolidated financial statements.

REGULATION

The Registrants are subject to regulation by various federal, state and local governmental agencies, including the regulations described below. The following discussion is based on regulation in the Registrants' businesses as of December 31, 2025.

Federal Energy Regulatory Commission

FERC has jurisdiction under the NGA and the NGPA, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in interstate commerce that are not first sales. FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. FERC also regulates the transmission and wholesale sales of electricity in interstate commerce, mergers, acquisitions and corporate transactions by electricity companies, energy markets, reliability standards and the issuance of short-term debt by public utilities regulated by FERC. FERC has authority to prohibit market manipulation in connection with FERC-regulated transactions, to conduct audits and investigations, and to impose significant civil penalties (up to approximately \$1.6 million per day per violation, subject to periodic adjustment to account for inflation) for statutory violations and violations of the FERC's rules or orders.

Indiana Electric is a "public utility" under the FPA and is subject to regulation by FERC. Houston Electric is not a "public utility" under the FPA and, therefore, is not generally regulated by FERC, although certain of its transactions are subject to limited FERC jurisdiction. FERC has certain responsibilities with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by Houston Electric and other utilities within ERCOT. FERC has designated NERC as the ERO to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system. The ERO and FERC have authority to (a) impose fines and other sanctions on applicable entities that fail to comply with approved standards and (b) audit compliance with approved standards. FERC has approved the delegation by NERC of authority for reliability in ERCOT to the Texas RE and in MISO to ReliabilityFirst Corporation. Neither Houston Electric nor Indiana Electric anticipate that the reliability standards proposed by NERC and approved by FERC will have a material adverse impact on their operations. To the extent that Houston Electric and Indiana Electric are required to make additional expenditures to comply with these standards, it is anticipated that Houston Electric and Indiana Electric will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT and the MISO, respectively, for electric transmission provided.

The FPA also provides that, whenever the Secretary of the U.S. Department of Energy determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, then the Secretary of the U.S. Department of Energy has the authority to require by order such temporary connections of facilities and such generation, delivery, interchange or transmission of electric energy as in the Secretary's judgment will best meet the demands of the emergency and serve the public interest.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, CenterPoint Energy and its consolidated subsidiaries are subject to reporting and accounting requirements and are required to maintain certain books and records and make them available for review by FERC and state regulatory authorities in certain circumstances.

For a discussion of the Registrants' ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Electric Transmission & Distribution (CenterPoint Energy and Houston Electric)

Houston Electric is a member of ERCOT, which serves as the independent system operator and regional reliability coordinator for member electric power systems in most of Texas. The ERCOT market represents approximately 90% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market operates under the reliability standards developed by NERC, approved by FERC and monitored and enforced by the Texas RE. The PUCT has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid.

The ERCOT ISO is responsible for operating the bulk electric power supply system in the ERCOT market. Houston Electric's transmission business, along with those of other owners of transmission facilities in Texas, supports the operation of the ERCOT ISO. Houston Electric participates with the ERCOT ISO and other ERCOT utilities to plan, design, obtain regulatory approval for and construct new transmission lines necessary to increase bulk power transfer capability and to remove existing constraints on the ERCOT transmission grid.

Houston Electric conducts its operations pursuant to a CCN issued by the PUCT that covers its present service area and facilities. The PUCT and certain municipalities have the authority to set the rates and terms of service provided by Houston Electric under cost-of-service rate regulation. Houston Electric holds non-exclusive franchises from certain incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give Houston Electric the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 40 years.

In ERCOT, end users purchase their electricity directly from certificated REPs. Houston Electric's distribution rates charged to REPs for residential and small commercial customers are primarily based on amounts of energy delivered, whereas distribution rates for a majority of large commercial and industrial customers are primarily based on peak demand. All REPs in Houston Electric's service area pay the same rates and other charges for transmission and distribution services. This regulated delivery charge may include the transmission and distribution rate (which includes municipal franchise fees), a DCRF mechanism for recovery of incremental distribution-invested capital above that which is already reflected in the base distribution rate, a TEEEF mechanism for recovery of costs associated with leasing and operating certain TEEEF, a TCRF mechanism for recovery of approved wholesale transmission cost changes billed by a transmission service provider, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility, an EECRF charge, and charges associated with securitization of regulatory assets, stranded costs and restoration costs. Transmission rates charged to distribution companies are based on amounts of energy transmitted under "postage stamp" rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay Houston Electric the same rates and other charges for transmission services.

With the IURC's approval, Indiana Electric is a member of the MISO, a FERC-approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over Indiana Electric's electric transmission and generation facilities as well as those of other utilities in the region. Indiana Electric is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing as determined by the MISO market. Indiana Electric also receives transmission revenue that results from other members' use of Indiana Electric's transmission system. Generally, these transmission revenues, along with costs charged by the MISO, are considered components of base rates and any variance from that included in base rates is recovered from or refunded to retail customers through tracking mechanisms.

For a discussion of certain of Houston Electric's and Indiana Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Electric Generation (CenterPoint Energy)

The energy and capacity secured from Indiana Electric's available generation resources are utilized primarily to serve the needs of retail electric customers residing within Indiana Electric's franchised service territory. The expenses and capital investments associated with operating Indiana Electric's generation facilities are recovered through IURC-approved base rates as well as periodic rate recovery mechanisms including the CECA, ECA, FAC, MCRA, and RCRA mechanism. Costs that are deemed unreasonable or imprudent by the IURC may not be recoverable through retail electric rates. Indiana Electric also receives revenues from the MISO to compensate it for benefits the generation facilities provide to the transmission system.

Proceeds from the sales of energy from Indiana Electric's generation facilities that exceed the requirements of retail customers are provided to retail electric customers.

The generation facilities owned and operated by Indiana Electric are subject to various environmental regulations enforced by the EPA and the IDEM. Operations of Indiana Electric's generation facilities are subject to regulation by the EPA and the IDEM as it pertains to water quality, waste disposal and air emissions from the generation facilities. For further discussion, see "Our Business — Environmental Matters" below.

For a discussion of Indiana Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Natural Gas (CenterPoint Energy and CERC)

In almost all communities in which CenterPoint Energy's and CERC's natural gas distribution businesses provide natural gas distribution services, they operate under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 10 to 30 years. CenterPoint Energy's and CERC's natural gas distribution businesses expect to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of CenterPoint Energy's and CERC's natural gas distribution businesses are subject to cost-of-service rate regulation by the relevant state public utility commissions and, in Texas, by those municipalities that have retained original jurisdiction. In certain of the jurisdictions in which they operate, CenterPoint Energy's and CERC's natural gas distribution businesses have annual rate adjustment mechanisms that provide for changes in rates dependent upon certain changes in invested capital or actual margins realized.

For a discussion of certain of CenterPoint Energy's and CERC's natural gas distribution businesses' ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Department of Transportation (CenterPoint Energy and CERC)

CenterPoint Energy and CERC are subject to regulation by PHMSA under the NGPSA and the HLPSA. The NGPSA delegated to PHMSA through DOT the authority to regulate gas pipelines. The HLPSA delegated to PHMSA through DOT the authority to develop, prescribe and enforce federal safety standards for the transportation of hazardous liquids by pipeline. Every four years PHMSA is up for reauthorization by the U.S. Congress and with that reauthorization comes changes to the legislative requirements that the U.S. Congress sets forth for the oversight of natural gas and hazardous liquid pipelines. In 2020, the PIPES Act was enacted. The PIPES Act reauthorized PHMSA through 2023 and imposed a few new mandates on the agency. The law establishes a PHMSA technology pilot, authorizes a new idled pipe operating status and contains process protections for operators during PHMSA enforcement proceedings. Section 114 of the PIPES Act is a self-mandating rule for natural gas pipeline operations like CERC's that focuses on processes and procedures to eliminate or reduce emissions during normal operations. Further, Section 113 of the PIPES Act directed PHMSA to develop regulations to require natural gas pipeline operators to implement leak detection and repair programs, as well as requirements for mitigating emissions in operations. The PIPES Act of 2023 was approved by the House Transportation and Infrastructure Committee on December 6, 2023 to reauthorize PHMSA's safety programs for the next four years. Final versions of the Section 113 Leak Detection and Repair, and Safety of Natural Gas Distribution Pipelines, 2020 PIPES Act rules remain frozen until a Department of Transportation appointee can review and proceed further.

In January 2021, PHMSA published a final rule amending the federal Pipeline Safety Regulations to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering systems.

CenterPoint Energy and CERC anticipate that compliance with PHMSA's regulations, performance of the remediation activities by CenterPoint Energy's and CERC's natural gas distribution businesses and intrastate pipelines, and verification of records on maximum allowable operating pressure will continue to require increases in both capital expenditures and operating costs. The level of expenditures will depend upon several factors, including age, location and operating pressures of the facilities. In particular, the cost of compliance with the DOT's integrity management rules will depend on integrity testing and the repairs found to be necessary by such testing. Changes to the amount of pipe subject to integrity management, whether by expansion of the definition of the type of areas subject to integrity management procedures or of the applicability of such

procedures outside of those defined areas, may also affect the costs incurred. Implementation by PHMSA of the PIPES Act, in particular the final rule implementing Section 113, acts reauthorizing PHMSA or other future acts may result in other regulations or the reinterpretation of existing regulations that could impact compliance costs. In addition, CenterPoint Energy and CERC may be subject to the DOT's enforcement actions and penalties if they fail to comply with pipeline regulations.

ENVIRONMENTAL MATTERS

The following discussion is based on environmental matters in the Registrants' businesses as of December 31, 2025. The Registrants' operations are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, electric transmission and distribution systems, steam electric and renewable generation systems and the facilities that support these systems, the Registrants must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact the Registrants' business activities in many ways, including, but not limited to:

- restricting the way the Registrants can handle or dispose of wastes, including wastewater discharges and air emissions;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action and monitoring to mitigate environmental conditions caused by the Registrants' operations or attributable to former operations;
- enjoining the operations of facilities with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for the Registrants' services by directly or indirectly affecting the use or price of fossil fuels, including, but not limited to, natural gas.

To comply with these requirements, the Registrants may need to spend substantial amounts and devote other resources from time to time to, among other activities:

- construct or acquire new facilities and equipment;
- acquire permits for facility operations or purchase emissions allowances;
- modify, upgrade or replace existing and proposed equipment; and
- decommission or remediate waste management areas, fuel storage facilities and other locations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, revocation of permits, the imposition of remedial actions and monitoring and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to assess, clean up and restore sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and/or property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Our obligations associated with these requirements change as administrations change and as legislatures and regulators pass new laws and regulations and amend existing ones. Therefore, it is difficult to project future costs of compliance and their impact on competition. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and monitoring, and actual future expenditures may be different from the amounts currently anticipated. The Registrants try to anticipate future regulatory requirements that might be imposed and plan accordingly to maintain compliance with changing environmental laws and regulations.

Based on current regulatory requirements and interpretations, the Registrants do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on their business, financial position, results of operations or cash flows. In addition, the Registrants believe that their current environmental remediation activities will not materially interrupt or diminish their operational ability. The Registrants cannot provide assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause them to incur significant costs. The following is a discussion of material current environmental issues, laws and regulations that relate to the Registrants' operations. The Registrants believe that they are in substantial compliance with these environmental laws and regulations.

GHG Emissions and Climate Change-Related Regulation and Compliance (*CenterPoint Energy*)

The issue of climate change has received focus at the state, federal and international level. As a result, from time to time, regulatory agencies have considered the modification of existing laws or regulations or the adoption of new laws or regulations addressing the emissions of GHG and other climate change-related matters on the state, federal or international level. On

January 20, 2025, President Trump signed an executive order to withdraw the United States from the Paris Agreement (which took effect on January 27, 2026), marking a significant shift in U.S. climate policy; on January 7, 2026, it was announced that the United States will withdraw from the United Nations Framework Convention on Climate Change, a treaty that underpins international efforts on global climate; and on February 12, 2026, the EPA announced the finalization of a rule repealing the Endangerment Finding (defined below) as it relates to new motor vehicles. Accordingly, our obligations associated with GHG emissions and climate change-related matters change as administrations change and as legislatures and regulators pass new laws and regulations and amend existing ones.

The EPA released its initial GHG regulation for fossil fuel-fired electric generating units in 2015. In April 2024, the EPA finalized the current New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, Reconstructed Fossil Fuel-Fired Units; and Repeal of the Affordable Clean Energy Rule, which applies new GHG performance standards for those existing coal-fired power plants expected to continue operation beyond December 31, 2029. The rule is currently being challenged by a variety of stakeholders in litigation before the Circuit Court of Appeals for the D.C. Circuit. In October 2024, the U.S. Supreme Court declined to stay the implementation of the rule while the rule is on judicial review. However, on June 17, 2025, the EPA proposed a rule to repeal GHG emission standards for fossil fuel-fired electric generating units, or in the alternative, to repeal a narrower set of requirements, including the emission guidelines for existing fossil fuel-fired steam electric generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification and the CCS-based standards for new base load stationary combustion turbines. Additionally, the IRA established the Methane Emissions Reduction Program, which imposes a charge on methane emissions from certain natural gas transmission facilities, the rules for which were finalized on November 18, 2024. However, on March 14, 2025, President Trump signed a Congressional Review Act resolution disapproving the EPA's final rule, thereby prohibiting the rule from taking effect, and the OBBBA postponed the imposition of the methane emissions charge to 2034. On September 16, 2025, the EPA proposed a rule to end the Greenhouse Gas Reporting Program ("GHGRP") for all sectors except petroleum and natural gas systems (excluding reporting for natural gas distribution, which would also be eliminated under the proposed rule). Reporting for petroleum and natural gas systems under the GHGRP would be deferred until 2034 under the proposal. On February 12, 2026, the EPA announced the repeal of the 2009 "Endangerment Finding" under the Clean Air Act, which found that GHG emissions endanger the public health and welfare of current and future generations and that emissions of GHGs from motor vehicles contribute to GHG pollution. The repeal calls into question the EPA's authority to regulate GHG emissions, as well as the EPA's prior scientific assessment of climate change risks. Litigation regarding the repeal is anticipated and it is unclear how the repeal will impact the EPA's regulation of GHG emissions going forward. On March 6, 2024, the SEC adopted final rules to require disclosure of certain climate-related information in registration statements and annual reports. Litigation challenging the rule was filed by multiple parties in multiple jurisdictions, which have been consolidated and assigned to the U.S. Court of Appeals for the Eighth Circuit. On September 12, 2025, the U.S. Court of Appeals issued an order to hold the petitions challenging the climate disclosure rules in abeyance pending further action by the SEC.

CenterPoint Energy has adopted energy transition goals. Because Texas is an unregulated market, CenterPoint Energy's Scope 2 emissions estimates do not take into account Texas electric transmission and distribution assets in the line loss calculation and, in addition, exclude emissions related to purchased power in Indiana between 2024 and 2026 as estimated. CenterPoint Energy's Scope 3 emissions estimates are based on the total natural gas supply delivered to residential and commercial customers as reported in the U.S. Energy Information Administration (EIA) Form EIA-176 reports and do not take into account the emissions of transport customers and emissions related to upstream extraction. These energy transition goals are expected to be used to position CenterPoint Energy to comply with regulatory requirements from any future administrations to further reduce GHG emissions. For more information regarding CenterPoint Energy's energy transition goals and their related risks, see "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — CenterPoint Energy is subject to operational and financial risks ...". CenterPoint Energy's energy transition goals are aligned with Indiana Electric's generation transition plan and are expected to position Indiana Electric to comply with future regulatory requirements related to GHG emissions reductions. Houston Electric, in contrast to some electric utilities including Indiana Electric, does not generate electricity, other than through TEEEF, and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, Houston Electric's and Indiana Electric's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within their respective service territories. Likewise, incentives to conserve energy or to use energy sources other than natural gas could result in a decrease in demand for the Registrants' services. Further, our third-party suppliers, vendors and partners may also be impacted by climate change laws and regulations, which could impact CenterPoint Energy's business by, among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to CenterPoint Energy. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics relative to other fossil fuels would be expected to benefit CenterPoint Energy and CERC and their natural gas-related businesses. At this time, however, we cannot quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on the Registrants' businesses.

Compliance costs and other effects associated with climate change, reductions in GHG emissions and obtaining renewable energy sources remain uncertain. Significant changes in policy due to administration change can create regulatory uncertainty. For example, the repeal of the Endangerment Finding could lead to a patchwork of conflicting state superfund laws and state regulation relating to climate change and GHG emissions. Although the amount of compliance costs remains uncertain, any new regulation or legislation relating to climate change will likely result in an increase in compliance costs. For example, CenterPoint Energy's and CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of their operations or would have the effect of reducing the consumption of natural gas. While the requirements of a federal or state rule remain uncertain, CenterPoint Energy will continue to monitor regulatory activity regarding GHG emission standards that may affect its business. Currently, CenterPoint Energy does not purchase carbon credits. In connection with its energy transition goals, CenterPoint Energy expects to purchase carbon credits in the future; however, CenterPoint Energy does not currently expect the number of credits, or cost for those credits, to be material.

Air Emissions

The Registrants' operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating facilities and natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions. The Registrants may be required to obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Failure to comply with these requirements could result in monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. The Registrants may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Water Discharges

The Registrants' operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material into wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of petroleum or other pollutants from the Registrants' pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Waters of the United States

On May 25, 2023, the U.S. Supreme Court issued a decision limiting the scope of federal jurisdiction over wetlands in the case of *Sackett v. Environmental Protection Agency*, and on August 29, 2023, the EPA issued a final rule that sought to conform with the U.S. Supreme Court decision. As a result of ongoing rulemaking litigation, the Registrants' operations in all states with the exception of Minnesota fall under the pre-2015 regulatory regime consistent with the Supreme Court decision in *Sackett*, while operations in Minnesota fall under the 2023 rule, as amended. However, on November 17, 2025, the EPA announced a proposed rule that seeks to further clarify the definition of "Waters of the United States." CenterPoint Energy is unable to predict the outcome of current or future litigation or regulatory proceedings, but does not expect a material impact on its operations relating to these rules. CenterPoint Energy will continue to monitor regulatory and legal developments relating to the Clean Water Act that may affect its business.

ELG

In 2015, the EPA finalized revisions to the existing steam electric wastewater discharge standards, which set more stringent wastewater discharge limits and effectively prohibited further wet disposal of coal ash in ash ponds. In February 2019, the IURC approved Indiana Electric's ELG Compliance Plan for its F.B. Culley Generating Station, which was completed in compliance with the requirements of ELG. On April 25, 2024, the EPA released its final Supplemental ELG and Standards for the Steam Electric Generating Point Source Category, and on December 31, 2025, the EPA published its final rule further extending the applicable compliance deadlines. The Registrants currently anticipate that they will be in compliance with the Supplemental ELG Guidelines and any extensions thereto at the Culley facility due to previous wastewater treatment upgrades.

Cooling Water Intake Structures

Section 316 of the federal Clean Water Act requires steam electric generating facilities use “best technology available” to minimize adverse environmental impacts on a body of water. In May 2014, the EPA finalized a regulation requiring installation of “best technology available” to mitigate impingement and entrainment of aquatic species in cooling water intake structures. Indiana Electric has completed the required ecological studies and anticipates timely compliance at its F.B. Culley facility in accordance with deadlines to be established by IDEM.

Hazardous Waste

The Registrants’ operations generate wastes, including some hazardous wastes, that are subject to the federal RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment, transport and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous wastewaters produced and other wastes associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes are still regulated under state law and the less stringent non-hazardous waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that would be subject to RCRA or comparable state law requirements.

Coal Ash

In 2015, the EPA finalized the CCR Rule. Indiana Electric historically operated three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility; these ash ponds are no longer in operation. Both the Culley East and A.B. Brown facility have been taken out of service and closure activities continue. The Culley West pond closure activities were completed in December 2020. For further discussion about Indiana Electric’s ash ponds, see Note 14(c) to the consolidated financial statements.

On April 25, 2024, the EPA released its final Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments rule (CCR Legacy Rule), which was published in the federal register in May 2024. The CCR Legacy Rule requires companies to investigate previously closed impoundments that were used historically for ash disposal or locations which have had ash placed on them in amounts set forth in the CCR Legacy Rule. The Registrants have completed their preliminary review of potential sites that will require further investigation under the CCR Legacy Rule and identified certain sites in Indiana for further evaluation. For further discussion about Indiana Electric’s sites identified pursuant to the CCR Legacy Rule, see Note 14(c) to the consolidated financial statements.

Liability for Remediation

CERCLA, also known as “Superfund,” and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of “hazardous substances” into the environment. Classes of PRPs include the current and past owners or operators of sites where a hazardous substance was released and companies that disposed or arranged for the disposal of hazardous substances at offsite locations such as landfills. Although petroleum, as well as natural gas, is expressly excluded from CERCLA’s definition of a “hazardous substance,” in the course of the Registrants’ ordinary operations they do, from time to time, generate wastes that may fall within the definition of a “hazardous substance.” CERCLA authorizes the EPA and, in some cases, third parties, to take action in response to threats to the public health or the environment and to recover the costs they incur from the responsible classes of persons. Under CERCLA, the Registrants could potentially be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for associated response and assessment costs, including for the costs of certain health studies.

Liability for Preexisting Conditions

For information about preexisting environmental matters, see Note 14(c) to the consolidated financial statements.

HUMAN CAPITAL

CenterPoint Energy believes its employees are its greatest asset, and their unique skills, knowledge, experience and backgrounds are critical to safely and reliably delivering electricity and natural gas to CenterPoint Energy's customers across its service territories. CenterPoint Energy's core values—safety, integrity, accountability, initiative and respect—guide how it makes decisions and provide the foundation for a strong culture of ethics where employees are responsible for upholding these values and following CenterPoint Energy's Ethics and Compliance Code.

The following table sets forth the number of employees by Registrant and reportable segment as of December 31, 2025:

Reportable Segment	Number of Employees			Number of Employees Represented by Collective Bargaining Groups		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Electric	3,516	3,153	—	1,896	1,705	—
Natural Gas	3,259	—	2,984	1,703	—	1,613
Corporate and Other (1)	2,019	—	—	113	—	—
Total	8,794	3,153	2,984	3,712	1,705	1,613

(1) Employees in the Corporate and Other reportable segment provide services to the Electric and Natural Gas reportable segments and the costs of these services have been charged directly to the Electric and Natural Gas reportable segments using assignment methods that management believes are reasonable. For further information, see Note 18 to the consolidated financial statements.

CenterPoint Energy's workforce includes 3,712 employees represented by collective bargaining agreements. For information about the status of collective bargaining agreements, see Note 8(j) to the consolidated financial statements.

Talent Attraction, Development and Retention. CenterPoint Energy's human capital priorities include attracting, retaining and developing high performing talent through its talent management activities. CenterPoint Energy endeavors to attract quality candidates through its recruitment and selection processes. CenterPoint Energy seeks to recruit qualified employees regardless of race, gender, color, sexual orientation, age, religion, national origin, or physical or mental disability. The CenterPoint Energy talent acquisition team engages with college campuses to create awareness of opportunities in engineering, finance and technical occupations, and maintains relationships with student organizations across CenterPoint Energy's service territories. CenterPoint Energy also maintains internship and apprenticeship programs that are designed to provide real-world experience, training and mentoring to interns and apprentices. Additionally, CenterPoint Energy works with other energy utility companies, associations, unions, educators and business partners to support workforce readiness and long-term talent development in the energy industry.

CenterPoint Energy's strategy to attract, retain and develop its employees combines talent discussions and succession planning as essential elements of workforce planning and development. To support its commitment to delivering electricity and natural gas safely and reliably, CenterPoint Energy focuses on the continued development of its greatest assets, its employees, to build a sustainable leadership pipeline. To meet the business' future needs, CenterPoint Energy's goal is to create great leaders capable of developing their employees, while supporting the business' goals and maintaining a high-performing workforce through employee engagement and workplace culture. CenterPoint Energy has a number of tools for leadership and employee development that expand opportunities available to employees. For example, CenterPoint Energy maintains a corporate university that offers a variety of content and resources to employees, including instructor-led and on-demand learning, to help meet employees' needs for professional, leadership and business unit-specific development. Additionally, CenterPoint Energy conducts regular talent discussions, including succession planning with various levels of leadership, to provide business continuity and identify its future leaders and opportunities. CenterPoint Energy invests in employee development throughout the year to align individual performance to business needs, drive development planning and support career progression. CenterPoint Energy's progress is reviewed regularly for continued improvement.

Engagement. CenterPoint Energy is dedicated to advancing an open and high-performing work environment where business results are achieved through the experience, skills, abilities and talents of the whole workforce. CenterPoint Energy aims to create a workplace where every employee is engaged, aligned with our values, strategy, goals and priorities, and understands how each person contributes to CenterPoint Energy's long-term performance. In 2025, CenterPoint Energy's senior leadership team conducted an employee engagement survey and held quarterly town hall meetings with employees to share key company updates, with employees across CenterPoint Energy participating in person or via video conference.

Compensation and Benefits. CenterPoint Energy is committed to providing its employees with competitive pay and benefits. Its compensation philosophy is to maintain employee total compensation that is competitive with the relevant markets, internally equitable, and based on company and individual performance. CenterPoint Energy expects that this will enable it to attract, motivate and retain employees with the skills and competencies necessary to achieve its business strategy. In addition to competitive compensation, CenterPoint Energy provides its employees with a comprehensive benefits package designed to help employees stay healthy, care for their families, plan for the future and enjoy peace of mind. The benefits package includes medical, dental, vision, life, disability and accidental insurance coverage; retirement, company match savings plans; paid time off, parental leave, wellness and employee assistance programs. The employee wellness resources encompass support for mental, financial and physical health.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS
(as of February 13, 2026)

Name	Age	Title
Jason P. Wells	48	Chair of the Board, President and Chief Executive Officer
Christopher A. Foster	47	Executive Vice President and Chief Financial Officer
Monica Karuturi	47	Executive Vice President and General Counsel
Jason M. Ryan	50	Executive Vice President, Regulatory Services and Government Affairs
Jesus Soto, Jr.	58	Executive Vice President and Chief Operating Officer

Jason P. Wells has served as Chair of the Board since October 8, 2025, and as President and Chief Executive Officer of CenterPoint Energy and a member of the Board since January 5, 2024. Previously he served as President and Chief Operating Officer of CenterPoint Energy from May 2023 to January 2024; as President, Chief Operating Officer and Chief Financial Officer of CenterPoint Energy from January 2023 to May 2023; and as Executive Vice President and Chief Financial Officer of CenterPoint Energy from September 2020 to December 2022. Prior to joining CenterPoint Energy, Mr. Wells served as Executive Vice President and Chief Financial Officer of PG&E Corporation, a publicly traded electric utility holding company serving customers in Northern and Central California through its subsidiary Pacific Gas and Electric Company, from June 2019 to September 2020. He previously served as Senior Vice President and Chief Financial Officer of PG&E Corporation from January 2016 to June 2019 and as Vice President, Business Finance of Pacific Gas and Electric Company from August 2013 to January 2016. PG&E Corporation filed Chapter 11 bankruptcy on January 29, 2019 and successfully emerged from bankruptcy on July 1, 2020. He also served in various finance and accounting roles of increasing responsibility at Pacific Gas and Electric Company. Mr. Wells earned his bachelor's degree and master's degree in accounting, both from the University of Florida. He is a certified public accountant (inactive). Mr. Wells serves on the Executive Committee and Board for the Greater Houston Partnership, the Advisory Board of the Kinder Institute for Urban Research at Rice University, and the Boards of Central Houston, Inc., M.D. Anderson Cancer Center, Performing Arts Houston and the United Way of Greater Houston.

Christopher A. Foster has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since May 2023. Previously, he served as Executive Vice President and Chief Financial Officer of PG&E Corporation, a publicly traded electric utility holding company serving customers in Northern and Central California through its subsidiary Pacific Gas and Electric Company, from March 2021 to May 2023. He previously served in various positions of increasing responsibilities at PG&E since 2011, including as Vice President and Interim Chief Financial Officer from September 2020 to March 2021, and Vice President, Treasury and Investor Relations from March 2020 to September 2020. PG&E Corporation filed Chapter 11 bankruptcy on January 29, 2019 and successfully emerged from bankruptcy on July 1, 2020. He earned his bachelor's degree from Michigan State University. Mr. Foster serves on the Board of Exploratorium, a San Francisco-based science and technology museum, as well as the Board of Directors of the Houston Parks Board.

Monica Karuturi has served as Executive Vice President and General Counsel of CenterPoint Energy since January 2022. She previously served as Senior Vice President and General Counsel from July 2020 to January 2022; as Vice President and Deputy General Counsel from April 2019 to July 2020; as Vice President and Associate General Counsel - Corporate and Securities from October 2015 to April 2019; and as Associate General Counsel - Corporate from September 2014 to October 2015. Prior to joining CenterPoint Energy, Ms. Karuturi served as counsel for LyondellBasell Industries for corporate and finance matters and strategic transactions. Ms. Karuturi earned her bachelor's degree from Brown University, master's degree in health policy and management from Columbia University, and juris doctorate from Georgetown University Law Center. Ms. Karuturi was appointed as a Commissioner of the Texas Access to Justice Commission by the Texas Supreme Court in June 2015 and served in this capacity until June 2021. She was also appointed as Chair of the Houston Bar Foundation in 2021 and served until December 2024. She currently serves as a member of the Board of Directors of Nextpower Inc. and the Houston Zoo.

Jason M. Ryan has served as Executive Vice President, Regulatory Services and Government Affairs of CenterPoint Energy since January 2022. He previously served as Senior Vice President, Regulatory Services and Government Affairs from July 2020 to January 2022; as Senior Vice President and General Counsel from April 2019 to July 2020; as Senior Vice President, Regulatory and Government Affairs from February 2019 to April 2019; as Vice President of Regulatory and Government Affairs and Associate General Counsel from March 2017 to February 2019; and as Vice President and Associate General Counsel from September 2014 to March 2017. He was appointed to the Texas Diabetes Council by Texas Governor Perry in 2013 for a term ending in 2019, and he has since been reappointed by Texas Governor Abbott twice (most recently in 2025 for a term ending in 2031). Mr. Ryan earned his bachelor's degree from the Texas McCombs School of Business and juris doctorate from the University of Texas School of Law. Mr. Ryan currently serves on the boards of the Lone Star Flight Museum and the Association of Electric Companies of Texas. He also serves on the executive committee of the legal committee of the American Gas Association.

Jesus Soto, Jr. has served as Executive Vice President, Chief Operating Officer of CenterPoint Energy since August 2025. Previously, he served as Executive Vice President, Utility Performance Solutions of Quanta Services, Inc., a publicly-traded energy infrastructure services company, from October 2023 to August 2025. He previously served as the Chief Operating Officer for Mears Group, Inc., a wholly-owned subsidiary of Quanta Services, Inc., from September 2019 to September 2023, and as Senior Vice President of Gas Operations for PG&E Corporation, a publicly traded electric utility holding company serving customers in Northern and Central California through its subsidiary Pacific Gas and Electric Company, from May 2012 to July 2019. Prior to joining PG&E Corporation, he served as Vice President of Operations Services and Vice President of Engineering and Construction for the Pipeline Group of El Paso Corporation, a former publicly traded natural gas and related energy products provider. Mr. Soto earned his bachelor's degree from the University of Texas at El Paso, his master's degree in civil engineering from Texas A&M University, and his master's degree in business administration from the University of Phoenix. Mr. Soto serves on the Board of Directors of GTI Energy, an energy technology development and training company, and as Chair of the Industry Pipeline Safety Management Systems Team of the American Petroleum Institute.

Item 1A. Risk Factors

CenterPoint Energy is a holding company that conducts all of its business operations through subsidiaries, primarily Houston Electric, CERC and SIGECO. The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this combined report on Form 10-K, summarizes the principal risk factors associated with the holding company and the businesses conducted by its subsidiaries. However, additional risks and uncertainties either not presently known or not currently believed by management to be material may also adversely affect CenterPoint Energy's businesses. For other factors that may cause actual results to differ from those indicated in any forward-looking statement or projection contained in this combined report on Form 10-K, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings" in Item 7, which should be read in conjunction with the risk factors contained in this Item 1A. Carefully consider each of the risks described below, including those relating to Houston Electric, LLC and CenterPoint Energy Resources Corp., which, along with CenterPoint Energy, Inc., are collectively referred to as the Registrants. Unless the context indicates otherwise, where appropriate, information relating to a specific Registrant has been segregated and labeled as such and specific references to Houston Electric and CERC in this section also pertain to CenterPoint Energy. In this combined report on Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries.

Risk Factors Affecting Operations

Electric Transmission, Distribution and Generation (CenterPoint Energy and Houston Electric)

Disruptions at third-party or Indiana Electric's power generation facilities, generation inadequacy, directives issued by regulatory authorities or other matters could cause interruptions in Houston Electric's and Indiana Electric's ability to provide transmission and distribution services and Houston Electric and Indiana Electric may not be able to promptly respond, repair and restart their facilities, which could adversely affect their businesses, financial condition, results of operations and cash flows.

Houston Electric owns the transmission and distribution infrastructure in its service territory that delivers electric power to its customers, but it does not own or operate any bulk power generation facilities. Indiana Electric owns and operates power generation facilities in addition to the transmission and distribution infrastructure in its service territory. Both Houston Electric and Indiana Electric must follow the directives issued by their independent system operator, ERCOT and MISO, respectively. ERCOT and MISO have in the past and may in the future issue directives requiring members to implement controlled outages as a result of an emergency or reliability issues. Houston Electric has faced and may in the future face challenges to its planning and preparation for such directives and its implementation of Load Shed, including, for example, allegations that it had discretion as to how to Load Shed and which customers experienced outages and the duration of those outages. As a result, claims and lawsuits could be filed against CenterPoint Energy for personal injury, property damage or other damage or loss as a result of its Load Shed planning, preparation, implementation, and decisions in order to meet the directives of ERCOT and MISO, respectively. For example, during the February 2021 Winter Storm Event, the ERCOT regulated Texas electric system experienced an unprecedented power generation shortage as the amount of electricity generated by the state's power generation companies was insufficient to meet the amount demanded by customers. This resulted in ERCOT directing TDUs to significantly Load Shed, which caused customer outages across the ERCOT electric grid of Texas, including in Houston Electric's service territory. CenterPoint Energy received various claims and lawsuits with respect to the February 2021 Winter Storm Event, alleging, among other things, wrongful death, personal injury, property damage and other injuries and damages. See Note 7 to the consolidated financial statements and "— Houston Electric's use of TEEEF ..." for further information. If power generation capacity is severely disrupted or is inadequate for any reason in the future or in the event of significant system disturbances, Houston Electric's or Indiana Electric's transmission and distribution services may be diminished, interrupted or halted, which could lead to prolonged customer outages, and Houston Electric and Indiana Electric may not be able to promptly repair and restart their facilities, which could adversely affect our businesses, financial condition, results of operations and cash flows. Further, as with the lawsuits filed in the aftermath of the February 2021 Winter Storm Event, claims and lawsuits could be filed against the Registrants, which could also adversely affect our business, financial condition, and results of operations.

Additionally, Indiana Electric's generating facilities are subject to operational risks, and Houston Electric and Indiana Electric are subject to risk relating to the generating facilities that supply the power transmitted by Houston Electric and Indiana Electric; these risks have in the past and may in the future result in service interruptions and unscheduled outages, unanticipated operation and maintenance expenses, reputational harm and increased purchase power costs. For example, in June 2022, F.B. Culley Unit 3, a coal-fired generation unit, experienced a boiler feed pump turbine failure that caused the unit to be out of service for nearly nine months. In this time frame, CenterPoint Energy purchased energy on the open market. Such open market purchases have and may again result in increased costs and have an adverse impact on our business, financial condition, results of operations and cash flows. Further, Indiana Electric is party to a number of PPAs with third parties. Indiana Electric's

operations may be disrupted or otherwise insufficient if third parties do not deliver required power under our PPAs. These risks can arise from circumstances such as facility shutdowns or malfunctions due to equipment failure or operator or other human error; aging infrastructure; interruption of fuel supply or increased prices of fuel as a result of, among other things, contract expirations, inflation and/or tariffs; disruptions in the production or delivery of electricity; inability to comply with regulatory or permit requirements; governmental action; labor disputes; severe weather; natural disasters; or cyberattacks, all of which could adversely affect Indiana Electric's and Houston Electric's businesses, including their financial condition, results of operations and cash flows. Further, Indiana Electric currently relies on coal for a portion of its generation capacity. Indiana Electric purchases the majority of its coal supply, and in 2025 purchased all of its coal supply, from a single, unrelated party and, although the coal supply is under long-term contract, the loss of this supplier or transportation interruptions could adversely affect its ability to deliver electricity to its customers and adversely impact Indiana Electric's business, financial condition, results of operations and cash flows. Future labor shortages in the coal industry as well as coal supply shortages (such as those experienced by Indiana Electric in 2021 and part of 2022), may lead to increased cost and have an adverse impact on our business, financial condition, results of operations and cash flows. Further, as Indiana Electric's generating facilities may experience unanticipated disruptions as a result of renewable supply shortages, including, but not limited to, unfavorable wind and solar conditions such as cloudy or windless days, and such disruptions could adversely affect its ability to deliver electricity to its customers and adversely impact Indiana Electric's business, financial condition, results of operations and cash flows.

The operations of Houston Electric and Indiana Electric are subject to the usual hazards associated with electricity transmission and distribution, including inclement or severe weather, natural disasters, including wildfires, mechanical failure, contact with electrified facilities by people, equipment, and debris, unscheduled downtime, equipment interruptions, loss or outage of key technology platforms or systems, contamination, remediation, explosions, fires, chemical spills, discharges or releases of toxic or hazardous substances and other environmental risks. Such hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment, including loss of transmission and distribution lines and related equipment and environmental damage, and may result in suspension of operations, disruption of service to customers, prolonged outages and the imposition of civil or criminal penalties. For example, in 2024, Hurricane Beryl caused significant damage to Houston Electric's electric delivery system and resulted in a substantial number of its customers being without power, many for extended periods of time. Although CenterPoint Energy currently maintains property and casualty insurance, this insurance is limited in scope and subject to exceptions, conditions and coverage limitations and may not cover the costs associated with potential hazards incident to Houston Electric and Indiana Electric's businesses, and there is no guarantee that the insurance that CenterPoint Energy currently maintains will continue to be available at rates we believe are reasonable.

Indiana Electric's execution of its generation transition plan is subject to various risks, including timely recovery of capital investments and increased costs and risks related to the timing and cost of development and/or construction of new generation facilities.

Indiana requires each electric utility to develop and submit an IRP to the IURC every three years, unless extended, that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable, cost effective electric service for the next 20-year period. Indiana Electric has used past IRPs and will continue to use future IRPs to evaluate its mix of generation resources. Indiana Electric engages with the communities it serves, its regulators and third-parties in developing its generation transition plan. Recent IRPs, including the 2025 IRP, have identified preferred portfolios that include a wider mix of generating resources such as coal-fired generation, solar, wind, solar with storage and dispatchable natural gas combustion turbines. While the IURC does not approve or reject Indiana Electric's IRP, the IURC does comment on the IRP. Indiana Electric is required to obtain a CPCN prior to constructing or acquiring generating resources. Indiana Electric also obtains IURC approval of PPAs and demand-side management plans to help support cost recovery.

Indiana Electric must manage several risks associated with its generation transition plan. The IURC may delay providing comments on an IRP, requiring Indiana Electric to either wait for comments or proceed to implement its IRP without IURC comments. The IURC comments may raise concerns with Indiana Electric's IRP that make it difficult to obtain approval of the generation transition plan if not addressed. There is no guarantee that the IURC will approve Indiana Electric's requests to implement part of its generation transition. If Indiana Electric fails to receive IURC approvals necessary to acquire the projects or resources identified in its IRP or if other governmental action is taken with respect to Indiana Electric's generation resources or generation transition plan, Indiana Electric may not be able to implement its generation transition plan in a timely manner or at all. For example, while Indiana Electric's 2025 IRP (similar to previous IRPs) preferred portfolios included the retirement of F.B. Culley Unit 2, a coal-fired generation unit, by the end of 2025, the U.S. Department of Energy issued emergency order 202(c) in December 2025 directing Indiana Electric to continue operating the unit through March 23, 2026. Additionally, changes in how renewable resources are accredited to meet MISO's planning reserve margin requirement have made it less economic to pursue these resources. In connection with its IRPs, Indiana Electric's determinations with respect to the appropriate mix of generation resources may change from plans that were previously announced. For example, while Indiana

Electric's 2022/2023 IRP recommended the conversion of F.B. Culley Unit 3 from coal to natural gas by 2027, the 2025 IRP re-evaluated this conversion in light of customer affordability concerns, among other things, and deferred the decision regarding F.B. Culley Unit 3's replacement to a future IRP. If Indiana Electric is unable to implement its generation transition plan, it may have an adverse effect on CenterPoint Energy's ability to execute on its energy transition goals, execute on its growth strategy, achieve its financial goals, and otherwise impact its business, financial condition, results of operations and cash flows.

Even if a generation project is approved, risks associated with the development or construction of any new generation exist, including new legislation or governmental action restricting or delaying new generation, moratorium legislation, changes to trade practices (including tariffs, bans, retaliatory trade measures taken against the United States or related governmental action), changes to business practice manuals of MISO or corresponding impacts such as interconnection delays (which may be exacerbated by significant new load additions), the ability to procure resources needed to build at a reasonable cost, scarcity of resources and labor, the ability to appropriately estimate costs of new generation, the effects of potential construction delays, project scope changes, and cost overruns, cost of and ability to meet capacity requirements and related customer affordability considerations. For example, due to shifting market dynamics, changing project considerations such as substantial delays in commercial operation dates (due in part to MISO interconnection delays), cost increases and concerns about customer affordability, Indiana Electric terminated several wind and solar projects in 2025. If Indiana Electric is unable to meet its generation needs through development or acquisition of new generation, it would be required to buy the necessary capacity and electricity on the open market. Such open market purchases may result in increased costs and may have an adverse impact on our business, financial condition, results of operations and cash flows. If we are unable to complete or acquire such generation facilities or resources, or if they do not perform as anticipated, our business, financial condition, results of operations and cash flows may be adversely affected.

Houston Electric's receivables are primarily concentrated in a small number of REPs, and any delay or default in payments of these receivables could adversely affect Houston Electric's business, financial condition, results of operations and cash flows.

Houston Electric's receivables from the distribution of electricity are collected from REPs that supply the electricity. As of December 31, 2025, Houston Electric provided electric delivery service to approximately 67 REPs. Adverse conditions, including, but not limited to, the February 2021 Winter Storm Event or other extreme weather (which may result in abnormal power prices), structural problems in the market served by ERCOT, the impact of public health events or similar occurrences, mismanagement by the REPs, inflation or financial difficulties of one or more REPs, have and may in the future impair the ability of these REPs to pay for Houston Electric's services or cause them to delay such payments. Houston Electric depends on these REPs to remit payments on a timely basis. Applicable PUCT regulations significantly limit the extent to which Houston Electric can apply normal commercial terms to otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and Houston Electric thus remains at risk for payments relating to services provided prior to any shift to another REP or provider of last resort. Houston Electric's PUCT-approved tariff outlines the remedies available to Houston Electric in the event that a REP defaults on amounts owed. Among the remedies available to Houston Electric are seeking recourse against any cash deposit, letter of credit, or surety bond provided by the REP or implementing mutually agreeable terms with the REP. Another remedy is to require that customers be shifted to another REP or a provider of last resort. Houston Electric thus incurs risk for payments related to services provided prior to the shift to another REP or the provider of last resort. A significant portion of Houston Electric's billed receivables from REPs are due from affiliates of NRG and Vistra Energy Corp. Houston Electric's aggregate billed receivables balance from REPs as of December 31, 2025 was \$279 million. Approximately 37% and 23% of this amount was owed by affiliates of NRG and Vistra Energy Corp., respectively. Any delay or default in payment by REPs could adversely affect Houston Electric's business, financial condition, results of operations and cash flows. If a REP was unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made regarding prior payments Houston Electric had received from such REP. For example, following the February 2021 Winter Storm Event, multiple REPs filed for bankruptcy. As of December 31, 2025 and 2024, as authorized by the PUCT, CenterPoint Energy and Houston Electric had a regulatory asset of \$7 million and \$8 million, respectively for bad debt expenses resulting from REPs' defaults on their obligations to pay delivery charges to Houston Electric, net of collateral and recovery in rates. See "— Rate regulation of the Registrants' electric ..." For further information on certain of Houston Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report.

Houston Electric's use of TEEEF is subject to various risks, potential performance issues and allegations about Houston Electric's procurement and deployment of the resources (including the planning, execution and effectiveness of the same), regulatory and environmental requirements, and timely recovery of capital.

Following the February 2021 Winter Storm Event, the Texas legislature passed a law to allow TDUs, such as Houston Electric, to lease and temporarily operate TEEEF during widespread power outages where ERCOT has ordered a TDU to Load Shed or the TDU's distribution facilities are not being fully served by the bulk power system under normal operations. In response to this legislation, Houston Electric began leasing large (27 MW to 32 MW) TEEEF and medium (5.7 MW) TEEEF. In 2023, the Texas legislature amended the law to allow wider use of TEEEF, and in response, Houston Electric has entered into contractual arrangements to facilitate access to small (200 kW to 1,250 kW) TEEEF units; the small TEEEF units represent approximately 4% of the MWs of Houston Electric's total portfolio of TEEEF assets. In 2025, following the passage of the TEEEF Rule, Houston Electric requested from the PUCT preapproval to lease small TEEEF units for a three-year term. These proceedings remain ongoing and, until PUCT preapproval is received, Houston Electric plans to maintain the current contractual arrangement providing access to the small TEEEF units on a month-to-month basis. See Note 7 to the consolidated financial statements for further information. Additionally, in June 2025, the law was further amended to provide that, effective on or after the date of the amendment's passage, TDUs may only enter into, renew or extend leases for TEEEF units with a maximum generation capacity of five or fewer MW and that are rapidly deployable. The law prescribes specific and limited use for TEEEF, and Houston Electric's TEEEF have limited generation capacity, such that in future events customers could still be without power despite deployment of TEEEF resources. Additionally, as further described below, the large TEEEF units (which represent approximately 91% of the MWs of Houston Electric's total portfolio of TEEEF assets as of December 31, 2025) were released to the greater San Antonio region as of June 2025 for a contractual term through March 2027 unless terminated earlier in accordance with the provisions of the ERCOT Transaction, and Houston Electric has proposed releasing the medium TEEEF units (which represent approximately 5% of the MWs of Houston Electric's total portfolio of TEEEF assets as of December 31, 2025).

If Houston Electric is unable to deploy sufficient TEEEF resources in time to respond to a particular event (including as a result of releasing TEEEF to third parties or similar transactions as further described below); if TEEEF resources fail to perform, or are perceived to fail to perform, as intended; if Houston Electric is otherwise unable, or perceived as unable, to provide back-up generation resources and restore power (such as in the event of ERCOT issuing a directive requiring TDUs to Load Shed); or if the use of TEEEF resources or their failure to perform causes or is alleged to cause any personal injury, property damage, or other damage or loss due to allegations Houston Electric failed to deploy such units reasonably or effectively and failed to respond to particular power outages, Houston Electric could be subject to claims, demands, litigation, liability, regulatory scrutiny, and loss of reputation and new legislation could be passed making it no longer viable for Houston Electric to lease TEEEF at the same or similar scale that it currently leases such resources or at all. For example, following Hurricane Beryl, various federal, state and local governmental and regulatory agencies and other entities called for or conducted inquiries and investigations into the efforts made by Houston Electric to prepare for, and respond to, this event, including, among other things, Houston Electric's procurement of TEEEF, and certain government officials argued that Houston Electric, rather than ratepayers, should be held responsible for paying approximately \$800 million (the amount the PUCT had previously approved Houston Electric to recover from ratepayers relating to Houston Electric's leasing of TEEEF). Ongoing and future inquiries, investigations and proposed legislation regarding Houston Electric's TEEEF could adversely affect our business, financial condition, results of operations and cash flows, including with respect to our recovery of costs incurred as a result of Hurricane Beryl or future severe weather events; the assessment of financial penalties; changes to Houston Electric's system, service territories, operations and/or regulatory treatment; and the viability for Houston Electric to continue leasing TEEEF.

In June 2025, Houston Electric entered into the ERCOT Transaction, subject to PUCT approval, to release its large TEEEF units to ERCOT at CPS Energy facilities to serve the greater San Antonio region until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction, reduce its TEEEF fleet capacity and reduce its rates to reflect the removal of the large TEEEF units from its fleet. Following the completion of service in the San Antonio area, Houston Electric anticipates that it would complete one or more future transactions involving its large TEEEF units; because the TEEEF units would not be available to serve customers during such time, Houston Electric plans to continue to not charge customers for these units for any future periods. Further, in November 2025, Houston Electric proposed to release its medium TEEEF units from its TEEEF fleet and remove the associated lease costs from its rates. Houston Electric also anticipates entering into and receiving revenue from future transactions involving its medium TEEEF units. There can be no assurance that the PUCT will approve the ERCOT Transaction and Houston Electric's proposal to release its medium TEEEF units. If the ERCOT Transaction and/or Houston Electric's proposal to release its medium TEEEF units are not approved, it may have an adverse effect on our business, financial condition, results of operations and cash flows, as well as potentially lead to negative consequences from regulatory authorities or other public authorities. Suitable future transactions may not be available on terms and conditions we find acceptable, or the expected benefits of Houston Electric's release of its large and medium TEEEF units

or any completed future transactions may not be realized fully or at all, or may not be realized in the anticipated timeframe, which could adversely impact our business, financial condition, results of operations and cash flows. Finally, if such transactions are successful and thereby result in Houston Electric having fewer TEEEF units to deploy in its service territory, and conditions occur that could be or are perceived to have the potential to be addressed by Houston Electric's deployment of TEEEF, Houston Electric could be subject to claims, demands, litigation, liability, regulatory scrutiny and loss of reputation.

Despite the recovery of certain TEEEF costs in the past, there can be no assurance that Houston Electric will seek to or be able to recover certain future TEEEF costs or be able to retain those costs previously approved for recovery. For example, in 2024, the TCA filed a complaint with the PUCT requesting that it end the cost recovery and return on investment on Houston Electric's large and medium TEEEF units as previously approved, and these proceedings remain ongoing. See Note 7 to the consolidated financial statements for further information. If Houston Electric is unable to recover or must return any or certain of its TEEEF costs, our business, financial condition, results of operations and cash flows may be adversely affected. Additionally, while Houston Electric has insurance coverage and indemnity rights for its use of TEEEF resources, if its insurers or indemnitors fail to meet their indemnity obligations, Houston Electric could be liable for personal injury, property damage, or other damage or loss. Further, TEEEF resources are subject to various environmental regulations and permitting requirements, which could have an impact on Houston Electric's ability to use these units. If Houston Electric is not in compliance with any environmental regulation or permitting requirement, Houston Electric could be subject to further potential liability. The use of TEEEF is also subject to various other requirements, and failure to comply with them could subject Houston Electric to additional liability as well as challenges to its use of TEEEF in general.

Natural Gas (CenterPoint Energy and CERC)

Access to natural gas supplies and pipeline transmission and storage capacity are essential components of reliable service for our natural gas business customers.

We depend on third-party service providers to maintain an adequate supply of natural gas and for available storage and intrastate and interstate pipeline capacity to satisfy our customers' needs, all of which are critical to system reliability. Substantially all of our natural gas supply is purchased on intrastate and interstate pipelines. If we are unable to secure an independent natural gas supply of our own or if third-party service providers fail to timely deliver natural gas to meet our requirements, the resulting decrease in natural gas supply in our service territories could have an adverse effect on our business, financial condition, results of operations and cash flows. Additionally, a significant disruption, whether through reduced intrastate and interstate pipeline transmission or storage deliveries or other events affecting natural gas supply, including, but not limited to, operational failures, hurricanes, tornadoes, floods, severe winter weather conditions, wildfires, acts of terrorism, human error or cyberattacks or changes in legislative or regulatory requirements, could also have a negative impact on our businesses, financial condition, results of operations and cash flows. Further, to the extent that our natural gas requirements cannot be met through access to or continued use of existing natural gas infrastructure or if additional infrastructure, including onshore and offshore exploration and production facilities, gathering and processing systems and pipeline and storage capacity is not constructed at a rate that satisfies demand, then our operations could be negatively affected.

We are subject to fluctuations in natural gas prices, which could affect the ability of our suppliers and customers to meet their obligations or may impact our operations, which could adversely affect our business, financial condition, results of operations and cash flows.

We are subject to risk associated with changes in the price of natural gas. The regional and other markets in which we purchase natural gas are competitive and can be subject to significant pricing volatility as a result of many factors, including inflation, adverse weather conditions, supply and demand changes, availability of competitively priced alternative energy sources, political and geopolitical instability, commodity production levels and storage capacity, energy and environmental legislation and regulations and economic and financial market conditions. The natural gas market has been, and may continue to be, volatile due to growing domestic demand, increased natural gas exports, weather and other factors. Significant increases in natural gas prices, such as those experienced during the February 2021 Winter Storm Event, might affect our ability to collect balances due from customers and could create the potential for uncollectible accounts expense to exceed the recoverable levels built into tariff rates. In addition, a sustained period of high natural gas prices could (i) decrease demand for natural gas in the areas in which we operate, thereby resulting in decreased sales and revenues and (ii) increase the risk that our suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase working capital requirements by increasing the investment that must be made to maintain natural gas inventory levels.

Our natural gas businesses must compete with alternate energy sources, which could result in less natural gas delivered and have an adverse impact on our business, financial condition, results of operations and cash flows.

Our natural gas businesses compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other natural gas distributors and natural gas marketers also compete directly with us for natural gas sales to end users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass our facilities and market, sell and/or transport natural gas directly to commercial and industrial customers. Any reduction in the amount of natural gas delivered by us as a result of competition with alternate energy sources may have an adverse impact on our business, financial condition, results of operations and cash flows.

Risk Factors Affecting Regulatory, Environmental and Legal Risks

Rate regulation of the Registrants' electric and natural gas businesses may delay or deny their ability to earn an expected return and fully and timely recover their costs.

The Registrants' electric and natural gas businesses are regulated by certain municipalities, state commissions and federal agencies, such as FERC. Their rates are set in comprehensive base rate proceedings (i.e., general rate cases) based on an analysis of their invested capital, their expenses and other factors in a designated test year (often either fully or partially historic), subject to periodic review and adjustments. Each of these rate proceedings is subject to third-party intervention and appeal, and the timing of a general base rate proceeding may be out of the Registrants' control. The Registrants can make no assurance that their or their subsidiaries respective base rate proceedings will result in requested or favorable adjustments to their rates, in full and timely cost recovery or approval of other requested items, including, among other things, capital structure and ROE. Moreover, these base rate proceedings have caused in certain instances, and in the future could cause, the Registrants' electric and/or natural gas businesses to recover their investments below their requested levels, below the national average return for utilities or below recently approved return levels for other utilities in their respective jurisdictions. For instance, in the 2024 Houston Electric general rate case, Houston Electric filed a base rate case seeking approval for revenue increases of approximately \$60 million and a 10.4% ROE, but pursuant to the final settlement agreement filed with the PUCT, Houston Electric received an overall revenue requirement decrease of approximately \$47 million to current revenues and a 9.65% ROE relative to the initial filing. To the extent the regulatory process does not allow the Registrants to make a full and timely recovery of appropriate costs, their businesses, financial condition, results of operations and cash flows could be adversely affected. Further, the Registrants or their subsidiaries might be required to implement additional measures, such as the adoption of ring-fencing measures by Houston Electric in connection with its 2019 rate case proceeding. Such additional measures may adversely impact the Registrants' businesses and could have an adverse effect on their businesses, financial condition, results of operations and cash flows.

The rates that Registrants' electric and natural gas businesses are allowed to charge may not match their costs at any given time, a situation referred to as "regulatory lag." Regulatory lag has been and may be exaggerated in the future under certain circumstances, such as increased capital investments that are recovered in arrears. For example, the MPUC ordered extraordinary gas costs incurred in the February 2021 Winter Storm Event be recovered over a 63-month period from 2022 — 2027 and CERC forego recovery of the associated carrying costs. Though several interim rate adjustment mechanisms have been approved by jurisdictional regulatory authorities and implemented by the Registrants and their subsidiaries to reduce the effects of regulatory lag (for example, CSIA, DCRF, DRR, DSMA, GRIP, RCRA, TCOS and TDSIC), such adjustment mechanisms are subject to the applicable regulatory body's approval, which we cannot assure would be approved, and are subject to certain limitations that may reduce or otherwise impede the Registrants' or their subsidiaries ability to adjust their rates or result in rates below those requested. Therefore, the Registrants can make no assurance filings for such mechanisms will result in favorable adjustments to rates or in full cost recovery. Further, from time to time, the Registrants' regulators approve the issuance of system restoration bonds or securitization bonds to facilitate the recovery of certain qualified costs, including costs incurred as a result of severe weather or to recover stranded asset costs. For example, Houston Electric is currently seeking to recover system restoration costs associated with Hurricane Beryl and certain other significant storms through the issuance and sale of non-recourse system restoration bonds. The issuance of system restoration bonds or securitization bonds may be delayed due to regulatory or other actions outside of our control. If the issuance of system restoration bonds or securitization bonds is delayed, we may not be able to recover our costs in a timely manner, which could have an adverse effect on CenterPoint Energy's, CERC's, and Houston Electric's businesses, financial condition, results of operations and cash flows.

Inherent in the regulatory process is some level of risk that jurisdictional regulatory authorities may challenge the reasonableness or prudence of operating expenses incurred or capital investments made by the Registrants or their subsidiaries and deny the full recovery of their cost of service in rates. For example, concerns about customer affordability could cause regulators to approve lesser amounts in ratemaking or cost recovery proceedings. From time to time, reviews and investigations

have caused in certain instances, and in the future could cause, the Registrants to recover their costs or investments below their requested levels. For example, in October 2022, the MPUC issued a written order disallowing recovery of approximately \$36 million of the \$409 million originally requested by CERC in connection with its recovery of costs incurred as a result of the February 2021 Winter Storm Event. Notwithstanding the application of such rate adjustment mechanisms, the regulatory process by which rates are determined is subject to change as a result of legislative processes, rulemakings or litigation, as the case may be, and may not always be available or result in rates that will produce recovery of the Registrants' or their subsidiaries' costs or enable them to earn their authorized return. New legislation could be adopted in any of the states in which we operate that could alter the regulatory framework and prevent us from getting timely recovery of our costs and investments. Additionally, changes to the rate case or interim adjustment mechanisms (including the termination of such mechanisms) could result in an increase in regulatory lag or otherwise impact the Registrants' ability to recover their costs in a timely manner. Decisions from regulators are typically subject to appeal, and any such appeal could further exacerbate regulatory lag and lead to additional uncertainty associated with rate case proceedings. The regulatory process may also be adversely affected by the political, regulatory and economic environment and customer affordability concerns in the states in which we operate. We are also affected by the actions of numerous advocacy groups, and success by any such groups in directly or indirectly influencing legislators and regulators could have a material adverse effect on our business, financial condition, results of operations and cash flows. To the extent the regulatory process does not allow the Registrants to make a full and timely recovery of appropriate costs, their businesses, financial condition, results of operations and cash flows could be adversely affected. For further information on rate case proceedings and interim rate adjustment mechanisms, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report.

The regulated utility businesses, and the energy industry as a whole, have experienced a period of rising costs and investments and an upward trend in spending, especially with respect to infrastructure investments (including those that have already been approved by a regulator). For example, Houston Electric's SRP, which was approved by the PUCT in November 2025, includes twenty-seven resiliency measures totaling approximately \$2.68 billion in capital investments and an estimated \$185 million in operations and maintenance expense. Rising costs and investments and the upward trend in spending is likely to continue in the foreseeable future and could result in more frequent rate cases and requests for, and the continuation of, cost recovery mechanisms, all of which could result in adverse cost recovery determinations and/or face resistance from customers and other stakeholders, especially in a rising cost environment, whether due to inflation, customer affordability concerns, tariffs or changes to governmental policies and programs, high fuel prices or otherwise, and/or in periods of economic decline or hardship. Significant increases in costs could increase financing needs and otherwise adversely affect our business, financial condition, results of operations and cash flows.

Our successful execution and completion of capital projects and programs, including those within our 10-year capital plan, are subject to substantial risks, and our business, financial condition, results of operations and cash flows could be materially affected should such efforts not be executed and completed as planned.

We are managing ongoing, and planning future, significant capital projects relating to, among other things, improvements to our electric and natural gas transmission and distribution infrastructure. The execution of our capital projects, including those within our 10-year capital plan, may not be completed in accordance with current expectations or produce the desired results. Our ability to execute and complete our capital projects, including Houston Electric's proposed 765 kV and other transmission projects, in a timely and cost-effective manner and within budget is contingent upon many variables and subject to substantial risks. These variables and risks include, but are not limited to, availability of and costs for materials, equipment, commodities and qualified labor; cost and availability of financing; cost of regulatory compliance; economic and market conditions; regulatory approvals, licensing and permitting; land and easement acquisition (including requirements and constraints relating to eminent domain); regulatory, political, public and community relations risks (including in relation to customer affordability concerns); tax law; our ability to capitalize on business opportunities and such opportunities providing desirable rates of return; load growth (including our forecasts thereof) and our ability to capitalize on opportunities relating thereto; safety and environmental requirements; the ability of third parties to provide timely and satisfactory performance under their contracts; delays and cost increases; and supply chains and material constraints. Certain events that may be beyond our control may occur that materially affect the schedule, cost and performance of these projects, including Houston Electric's proposed 765 kV and other transmission projects. These events may relate to facing public and policymaker opposition to the projects or the real or perceived cost of such projects; delays in obtaining permits; challenges in securing sufficient land/easements for projects (including challenges to our use of eminent domain); shortages in materials and qualified labor; third parties not performing as expected or required under their contracts and/or experiencing financial problems that inhibit their ability to fulfill their obligations under contracts; supply chain delays or disruptions; changes in the scope and timing of projects; strikes; and adverse weather conditions. For example, our failure to capitalize on the opportunities presented by these developments or potential large load customers delaying or cancelling their planned projects could lead to delays or the cancellation of the projects

included in our 10-year capital plan. Additionally, regulators may investigate the prudence of costs in our rates and examine, among other things, the reasonableness or prudence of our level of expenditures (including costs associated with our capital projects). If we do not execute or complete our capital projects, including those within our 10-year capital plan, in accordance with current expectations or if our capital plan does not produce the desired results, our business, financial condition, results of operations and cash flows could be materially affected.

We face risks related to project siting, financing, construction, permitting, governmental approvals, public opposition, and the negotiation of project development agreements that may impede our development and operating activities.

Houston Electric, Indiana Electric and CERC own, develop, construct, manage and operate electric transmission, distribution and generation facilities or natural gas distribution facilities, as applicable. A key component of our growth is our ability to construct and operate these facilities. As part of these operations, we must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. We have previously experienced delays in receiving approval with regards to certain permits and licenses, and have had investigations and enforcement actions with regards to certain of our projects, which have caused delays to our projects in the past. Our projects, such as in the case of Houston Electric's proposed 765 kV and other transmission projects, have faced and may in the future face opposition from individuals, community organizations, environmental and other activist groups, and other public-interest entities. In the future, these approvals may not be granted in a timely manner (including due to potential staffing issues at U.S. regulatory agencies) or at all or may be modified, rescinded or fail to be extended for a variety of reasons, including due to legal or regulatory changes or political, public and community relations pressure. Should we in the future be unsuccessful in obtaining necessary licenses or permits on acceptable terms or resolving third-party challenges to such licenses or permits, should there be a delay in obtaining or renewing necessary licenses or permits, or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances, our future net income and cash flows could be reduced and our business, financial condition and results of operations could be impacted. Any failure to negotiate successful project development agreements for new facilities with third parties could also have adverse effects.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could negatively affect our financial results.

The Registrants are subject to numerous legal proceedings, including lawsuits and environmental matters in addition to regulatory proceedings, the most significant of which are summarized in Note 14 to the consolidated financial statements. Litigation is subject to many uncertainties; recent trends have shown jury verdicts, settlements and other liability have been significantly increasing; and the Registrants cannot predict the outcome of all matters with assurance. Additionally, under some circumstances, the Registrants could potentially have claims filed against them or incur liabilities associated with assets and businesses no longer owned by them as a result of sales, divestitures or other transfers to third parties who may be unable to fulfill their indemnity obligations to the Registrants. Final resolution of these matters, or any potential future claims or liabilities, may require additional expenditures over an extended period of time that may be in excess of established insurance or reserves and may have an adverse effect on the Registrants' businesses, financial condition, results of operations and cash flows. For further information, see "— Our insurance coverage may not..."

Customers', investors', legislators', regulators', creditors', rating agencies' and other stakeholders' opinions of us are affected by many factors, including actual or perceived system reliability and safety, the speed of our response to service interruptions, rates and customer affordability, our ability to successfully execute our capital plan, media coverage and actions by third parties, and negative opinions developed by such stakeholders could harm our reputation and have an adverse impact on our business, financial condition, results of operations and cash flows.

Our results are influenced by the expectations of our customers, investors, legislators, regulators, creditors, rating agencies and other stakeholders. Those expectations are based, in part, on the actual or perceived reliability, safety and affordability of our utility services. Our actual or perceived ability to prevent, mitigate, prepare for and timely respond to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by severe weather, physical or cybersecurity incidents or other unanticipated events, as well as our own or third parties' actions or failure to act, can affect customer, regulator and legislator satisfaction or potentially subject us to regulatory action and litigation. For example, CenterPoint Energy, CenterPoint Energy Service Company, LLC and Houston Electric are subject to litigation and claims arising out of Hurricane Beryl and various federal, state and local governmental and regulatory agencies and other entities called for or conducted inquiries and investigations into Hurricane Beryl and the efforts made by Houston Electric to prepare for, and respond to, this event, including the associated electric service outage issues. Ongoing and future inquiries, investigations and proposed legislation regarding Hurricane Beryl could adversely affect our business, financial condition, results of operations and cash flows, including with respect to our recovery of costs incurred as a result of Hurricane Beryl or future severe weather events; the assessment of financial penalties; changes to Houston Electric's system, service territories, operations and/or

regulatory treatment; and the viability for Houston Electric to continue leasing TEEEF. The level of rates and actual or perceived affordability of our services, the timing and magnitude of rate increases, and the volatility of rates can also affect the opinions of customers, legislators, regulators and other political figures of us. For example, in 2025, the Governor of Indiana directed the commissioner of the OUCC to evaluate utilities' profits and find cost-saving measures to ease the financial burden on customers. Our ability to successfully execute our capital plan may also affect customers', investors', legislators', regulators', creditors', rating agencies' and other stakeholders' opinions and actions. Opinions of us can additionally be affected by media coverage, including social media, which may include information, whether factual or not, that damages our brand and reputation. Our efforts to secure permits and/or acquire land and easements (including through eminent domain) for infrastructure investments, including with respect to Houston Electric's proposed 765 kV and other transmission projects, as well as execute on and/or obtain regulatory approvals for transmission, generation and other facilities can also affect opinions of us. We are also subject to adverse publicity related to actual or perceived environmental practices or impacts, including in relation to climate change and our ability to timely achieve our energy transition goals, as well as negative opinions regarding the appropriateness of our climate-related goals. If customers, investors, legislators, regulators, creditors, rating agencies or other stakeholders have or develop a negative opinion of us or our utility services, this could result in, among other things, less favorable legislative and regulatory outcomes (including but not limited to failure to obtain requested approvals on capital investments) or increased regulatory oversight, negative effects on our access to, and the cost of, capital, project delays or cancellations, increased litigation and negative public perception. The foregoing may harm our reputation and have adverse effects on our business, financial condition, results of operations and cash flows.

We are subject to operational and financial risks and liabilities arising from environmental laws and regulations, including regulation of CCR, climate change legislation and certain local initiatives that seek to limit fossil fuel usage.

Our operations are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, electric generating facilities and electric transmission and distribution systems, and the facilities that support these systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, including among others, restricting the use of fossil fuels through future climate legislation or regulation, restricting the use of natural gas-fired appliances in new homes, limiting airborne emissions from generating facilities, restricting the way we manage wastes, including wastewater discharges, air emissions and CCR removal, and requiring remedial action or monitoring to mitigate environmental actions caused by our operations or attributable to former operations. Environmental laws and regulations applicable to our operations are complex and subject to continued uncertainty, and we are subject to risks from changing or conflicting interpretations of existing laws, modifications to existing laws, new laws, and new or modified permit terms. We may need to spend substantial amounts and devote other resources from time to time to comply with these requirements. Further, in the course of operations we have released, and may in the future inadvertently release, various contaminants. Any such releases could have a significant impact on the environment and result in significant fines. Failure to comply with applicable environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including measures taken by individuals and non-governmental organizations seeking to enforce environmental laws against us or allege a failure to comply with such laws, and could lead to the assessment of monetary penalties, which we have been subject to from time to time, revocation of permits, the imposition of remedial actions, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict joint and several liability for costs required to clean, restore and monitor sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Regulatory agencies have also adopted, and from time to time consider adopting, new legislation and/or modifying existing laws and regulations to reduce GHGs. There continues to be a wide-ranging policy and regulatory debate, at the state level, nationally and internationally, regarding the possible means for their regulation. Although the United States withdrew from the Paris Agreement in 2026, and more recently the United Nations Framework Convention on Climate Change, and the current federal administration has revised and is expected to further revise compliance requirements under a number of federal environmental regulatory programs, many states and localities continue to pursue their own climate policies, and differences in energy policy priorities adopted by future federal administrations could result in additional GHG reduction requirements in the United States. As a distributor and transporter of natural gas and electricity, and a generator of electricity in Indiana, the Registrants' revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of their operations or that would have the effect of reducing the consumption of natural gas or electricity or prevent the use of certain fuel types. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be greater than the amounts we currently anticipate, which could adversely affect our business, financial condition, results of operations and cash flows. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a

decrease in demand for our services. For further discussion, see “Business—Environmental Matters” in Item 1 and “—Our natural gas businesses must compete with...”

Evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels may have substantial impacts on our electric generation and natural gas businesses. For example, because Indiana Electric currently relies on coal for a portion of its generation capacity, certain financial institutions may choose not to participate in CenterPoint Energy’s financing arrangements until future coal generation closures satisfy their thresholds for investments. Further, some investors choose to not invest in CenterPoint Energy due to CenterPoint Energy’s and CERC’s use of fossil fuels. Also, certain cities in CenterPoint Energy’s and CERC’s operational footprint have discussed the adoption of initiatives to prohibit the construction of new natural gas facilities that would provide service and focus on electrification. For example, Minneapolis has adopted carbon emission reduction goals in an effort to decrease reliance on fossil natural gas. Certain state and local governments have also passed, or are considering, legislation banning the use of natural gas-fired appliances in new homes, which could affect consumer use of natural gas. Should such bans be enacted within CenterPoint Energy’s and CERC’s operational footprint, they could adversely affect consumer demand for natural gas. Any such initiatives and legislation could adversely affect CenterPoint Energy’s and CERC’s businesses, financial condition, results of operations and cash flows.

Further, certain investors, lenders, regulators and other stakeholders are focusing on issues related to environmental justice, which may result in increased scrutiny of our applicable regulatory processes and additional costs of compliance or may adversely affect our reputation. While President Trump in 2025 signed an executive order calling to terminate all environmental justice offices and positions in the federal government, as well as any environmental justice initiatives, programs or other activities, the focus on environmental justice matters by certain stakeholders may nevertheless provide communities opposed to our operations with greater opportunities to challenge or delay our projects. Opposition to our projects or successful challenges or appeals to permits issued for our projects could result in cancellation of such projects and the loss of investments we have made with respect thereto.

CenterPoint Energy is subject to operational, financial and other risks and potential liabilities associated with our sustainability and related activities, including the implementation of and efforts to achieve our energy transition goals.

CenterPoint Energy has adopted energy transition goals and its analysis and plans for execution require it to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees, and our ability to achieve these goals will ultimately be driven by the needs of our business, the needs and desires of the customers, jurisdictions and other stakeholders we serve and our performance for our shareholders. In addition, forecasting is inherently speculative and the trajectory of the greater energy transition is uncertain. Should one or more of CenterPoint Energy’s underlying assumptions require updating, our actual results and ability to make progress towards and achieve our energy transition goals and the timing thereof could differ materially from its expectations, and CenterPoint Energy may elect to modify or update such goals. Further, there can be no guarantee that CenterPoint Energy will sustain or achieve these goals. Certain of the assumptions that could impact CenterPoint Energy’s ability to meet our energy transition goals and the timing thereof include, but are not limited to: GHG emission levels, service territory size, capacity needs and customer demand remaining in line with CenterPoint Energy’s expectations when such goals were announced, including with respect to demand for our services and in relation to the recent sale of CenterPoint Energy’s Louisiana and Mississippi natural gas LDC businesses and the announced sale of CenterPoint Energy’s Ohio natural gas LDC business; the ability to appropriately estimate and effectively manage business opportunities from and maintain reliability in connection with new customers and load growth resulting from, among other things, expansion of data centers (associated with, among other things, increasing demand for AI), energy refining and exports, advanced manufacturing and logistics in our service territories; regulatory approvals related to Indiana Electric’s generation transition plan and our ability to obtain such approvals; the ability to execute anticipated divestitures, portfolio optimizations or other strategic transactions; interconnection delays in the footprints of regional transmission organizations and/or interconnection costs; cost and affordability of customer rates and related concerns; customer demand for GHG emission free or lower GHG emissions energy; impacts of regulations, legislation or other governmental action, including those related to our operation of certain generating facilities (including the U.S. Department of Energy’s December 2025 emergency 202(c) order directing Indiana Electric to continue operating F.B. Culley Unit 2 through March 23, 2026), the environment and tax (including the effects of the OBBBA, Executive Order 14315, the IRA and any further changes to or the repeal of the renewable energy tax credits enacted in the IRA); federal and state executive, legislative and regulatory actions (including regulatory uncertainty resulting from changes in federal energy policy) and support for certain types of generation; impacts of future carbon pricing regulation or legislation, including a future carbon tax; price, availability and regulation of carbon offsets; price of fuel, such as natural gas; cost and technological development/innovation, adoption and commercialization of energy generation technologies, such as wind and solar, natural gas and storage solutions, and alternative energy, including electric vehicles; our ability to implement our modernization plans for pipelines and facilities; the ability to complete and timely implement and maintain system reliability during and after transitioning to generation alternatives to

Indiana Electric's coal generation; execution of the retirement or fuel conversion of Indiana Electric's coal facilities on anticipated timelines or at all; the ability to construct and/or permit new natural gas pipelines; the ability to procure resources needed to build at a reasonable cost, the lack of or scarcity of resources and labor, any project cancellations, construction delays or overruns (including as a result of changes in U.S. or foreign trade policies) and the ability to appropriately estimate costs of new generation; impact of any supply chain disruptions; changes in applicable standards, metrics, methodologies or frameworks; and enhancement of energy efficiencies.

Our businesses have in the past and may in the future face increased scrutiny from investors, governmental authorities and other stakeholders related to our sustainability practices, including our human capital management activities, as well as the goals, targets, and objectives we announce, our methodologies and timelines for pursuing them, our progress towards achieving them and related disclosures. We could also face challenges with managing conflicting requirements and our various stakeholders' expectations. We may be unable to satisfy all of our stakeholders, and to the extent our sustainability practices (including our human capital management activities) do not align with investor or other stakeholder expectations and standards, which continue to evolve, vary, and sometimes conflict, our businesses, including our reputation, ability to attract or retain employees, and attractiveness as an investment or business partner could be negatively affected and we could be exposed to enforcement actions and litigation. Similarly, our failure or perceived failure to pursue, fulfill or demonstrate meaningful progress towards our sustainability-focused goals, targets and objectives, to comply with or otherwise meet ethical, environmental or other standards, regulations or expectations, which may be varied or conflicting, or to satisfy various reporting standards with respect to these matters (including if there are real or perceived inaccuracies in the data and information we report or if we are exposed to allegations that certain public statements regarding sustainability-related matters are false and misleading "greenwashing" campaigns), within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and litigation.

Developing and implementing plans for compliance with voluntary climate commitments can lead to additional capital, personnel and operation and maintenance expenditures and could significantly affect the economic position of existing facilities and proposed projects. To the extent that we believe any of these costs are recoverable in rates, cost recovery could be resisted by our regulators and the public, and our regulators might attempt to deny or defer timely recovery of these costs. Moreover, we cannot predict the ultimate impact of achieving our emissions reduction goals, or the various implementation aspects, on our system reliability or our business, financial condition, results of operations and cash flows.

We are subject to extensive regulation, which could result in higher costs for system improvements, as well as fines or other sanctions.

In the planning and management of our operations, we must address existing and proposed laws and regulations regarding safety, reliability and other matters, as well as potential changes in regulatory frameworks, including reinterpretation of such regulations, initiatives by federal and state legislatures, regional transmission organizations (e.g., ERCOT and MISO), utility regulators, and taxing authorities, and actions by local jurisdictions regarding such matters. As has occurred in the past, if it were determined that we failed to comply with applicable laws and regulations or with applicable tariff provisions regarding such matters, we could become subject to fines, penalties, refund or disgorgement orders, or disallowed costs, or be required to implement additional compliance or remediation programs, the cost of which could be material. We cannot predict the impact of new laws, rules, regulations, tariffs, principles, or practices by federal or state agencies or regional transmission operators, or challenges or changes to present laws, rules, regulations, tariffs, principles, or practices and the interpretation of any adoption or change. Significant changes in the nature of the regulation of our businesses, including expiration or discontinuation of, or significant changes to, existing regulatory mechanisms, and the current federal administration's approach to U.S. energy policy and resultant changes in regulatory enforcement priorities, and/or evolving interpretations of existing regulatory requirements, could require changes to our business planning, strategy and management of our businesses and could adversely affect our business, financial condition, results of operations and cash flows.

Houston Electric and Indiana Electric are members of ERCOT and MISO, respectively, which serve the electric transmission needs of their applicable regions. As a result of their respective participation in ERCOT and MISO, Houston Electric and Indiana Electric do not have sole operational control over their transmission facilities and are subject to certain costs for improvements to these regional electric transmission systems. In addition, FERC has jurisdiction with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by Houston Electric and other utilities within ERCOT and Indiana Electric and other utilities within MISO, respectively. FERC has designated NERC as the ERO to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system. FERC has approved the delegation by NERC of authority for reliability in ERCOT to the Texas RE, a Texas non-profit corporation, and for reliability in the portion of MISO that includes Indiana Electric to Reliability First Corporation, a Delaware non-profit corporation. Compliance with mandatory reliability standards may subject Houston Electric and Indiana Electric to higher operating costs and may result in increased capital expenditures, which may not be fully recoverable in rates. Houston Electric

and Indiana Electric have received fines in the past for noncompliance. If Houston Electric or Indiana Electric were to be found to be in noncompliance with applicable mandatory reliability standards again, they would be subject to additional sanctions, including monetary penalties, which could range as high as over a million dollars per violation per day, and non-monetary penalties, such as having to file a mitigation plan to prevent recurrence of a similar violation and having certain milestones in such plan tracked.

Additionally, compliance with existing and potential new regulations related to CERC's operation and maintenance of natural gas infrastructure could result in significant costs. PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with regulations related to CERC's operation and maintenance of natural gas infrastructure, such as leak detection surveys and corrosion and critical valve inspections, and we systematically monitor and renew infrastructure over time; however, CERC has failed to maintain compliance with applicable regulations in the past and has received fines for past noncompliance. A significant incident or material finding of non-compliance in the future could result in enforcement action, penalties, higher costs of operations and adverse impacts on our regulatory proceedings, any of which could have an adverse effect on our business, financial condition, results of operations and cash flows.

Our businesses may be adversely affected by the intentional misconduct of our employees, consultants, contractors, suppliers and vendors.

We are committed to living our core values of safety, integrity, accountability, initiative and respect and complying with all applicable laws and regulations. Despite that commitment and efforts to prevent misconduct, it is possible for employees, consultants, contractors, suppliers and vendors to engage in intentional misconduct, fail to uphold our core values, and violate laws and regulations for individual gain through contract or procurement fraud, misappropriation, bribery or corruption, fraudulent related-party transactions and serious breaches of our Ethics and Compliance Codes and other policies. If such intentional misconduct by employees, consultants, contractors, suppliers and vendors should occur, it could result in substantial liability, higher costs, increased regulatory scrutiny and negative public perceptions, any of which could have an adverse effect on our business, financial condition, results of operations and cash flows. From time to time, including as part of our Ethics and Compliance program's efforts to detect misconduct, we become aware of and expect to continue to become aware of instances of misconduct by employees, consultants, contractors, suppliers and vendors, which we investigate, remediate and disclose as appropriate and proportionate to the incident.

Risk Factors Affecting Financial, Economic and Market Risks

Disruptions to the global supply chain, inflation, labor shortages and scarcity of certain materials may impact our operations, which could have an adverse impact on our ability to execute our capital plan and on our business, financial condition, results of operations and cash flows.

The global supply chain has experienced and may continue to experience significant disruptions due to a multitude of factors, such as geopolitical and economic uncertainty, regulatory and policy instability, tariffs and changes in U.S. and foreign trade policy, changes in laws (including tax laws), executive orders, the COVID-19 pandemic, labor shortages, resource availability, long lead times, manufacturer production limitations, delivery delays, inflation, severe weather events and disruptions to internal or international shipping, including as a result of armed conflicts, and these disruptions have adversely impacted the utility industry. We, as well as other companies in our industry, have experienced supply chain disruptions, and we may continue to experience this in the future. Moreover, inflation and high interest rates have contributed, and may continue to contribute, to increased prices for materials and services experienced by us and other companies in our industry. We have also faced, and may continue to face, a shortage of experienced and qualified personnel in certain positions, which has resulted in increased competition for skilled labor and wage inflation. Additionally, increased demand for materials necessary for our business has resulted, and may continue to result, in greater competition for and scarcity of such materials. For example, the increase in demand for electricity across the United States has contributed to large demand increases for transformers, which has caused and may continue to cause supply shortages for transformers. Examples of materials necessary for our business that we and our industry have experienced difficulties in procuring include transformers, wires, cables, meters, poles, electronic components, steel, aluminum and solar panels. If the supply chain disruption, inflation, labor shortages and scarcity of certain materials persist or worsen, we and the third parties that we contract with may experience difficulties in procuring the resources and labor necessary to operate our businesses in a timely and cost-efficient manner or at all, which could adversely impact, among other things, our ability to perform storm restoration activities, execute on our 10-year capital plan, execute Indiana Electric's generation transition plan and/or achieve our energy transition goals. Even if we are able to procure the necessary resources and labor, we might not be able to do so at a reasonable cost or in a timely manner, which could result in project

cancellations or scope changes, delays, cost overruns, under-recovery of costs, customer affordability concerns and challenges to our ability to remain in compliance with applicable laws, regulations and policies. If we are unable to fully execute on capital plans, our business, financial condition, results of operations and cash flows may be adversely affected.

If we are unable to arrange future financings on acceptable terms, our ability to finance our capital expenditures and operations or refinance outstanding indebtedness could be limited.

Our businesses are capital intensive, with significant and increasing capital spending expected in future periods. We rely on various sources to finance our capital expenditures and operations. For example, we depend on (i) long-term debt, (ii) borrowings through our revolving credit facilities and, for CenterPoint Energy and CERC, commercial paper programs and (iii) if market conditions permit, issuances of additional shares of common stock or shares of preferred stock by CenterPoint Energy, including through our at-the-market program. We may also use such sources to refinance any outstanding indebtedness as it matures. Additionally, from time to time, our operating subsidiaries, including Houston Electric and CERC, may rely on intercompany borrowings from CenterPoint Energy that may be sourced from CenterPoint Energy's external financings. These arrangements could expose us to risks, including exposure to losses upon the occurrence of certain events related to the development, construction, operation or financing of applicable projects. As of December 31, 2025, CenterPoint Energy had nearly \$23 billion of outstanding indebtedness on a consolidated basis, which included \$714 million of non-recourse Securitization Bonds. For information on outstanding indebtedness of CenterPoint Energy, Houston Electric and CERC as well as future maturities, see Note 12 to the consolidated financial statements.

In addition, external sources of capital may not be adequate or available on reasonable terms. If we are unable to arrange future financings on acceptable terms, our ability to finance our operations and capital expenditures, including our 10-year capital plan announced in 2025 and increased in February 2026 (through which CenterPoint Energy plans to invest at least \$65.5 billion through 2035), or refinance our outstanding indebtedness could be limited. Any of these outcomes could have a material adverse effect on our business, financial condition, results of operations and cash flows. Our future financing activities may be significantly affected by, among other things:

- general economic and capital market conditions, including inflation and recession;
- credit availability from financial institutions and other lenders;
- investor confidence in us, our regulatory environment, our industry and the markets in which we operate;
- the future performance of our businesses;
- maintenance of acceptable credit ratings;
- actions from the Federal Reserve, including changes in interest rates and unanticipated actions;
- market expectations regarding our future earnings and cash flows;
- investor willingness to invest in companies associated with fossil fuels;
- our ability to access capital markets on reasonable terms;
- acceleration of payments or decreased credit lines
- timing and adequacy of future cost recovery, including securitizations, by jurisdictions in which we operate;
- changes in regulation, governmental policy (including tax and trade policy, such as tariffs) or governmental programs (including tax incentives or tax credits, loans, grants, guarantees and other subsidies); and
- provisions of relevant securities laws and our ability to obtain required regulatory authorization for issuances of securities.

The Registrants' current credit ratings and any changes in credit ratings in 2025 and to date in 2026 are discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Other Matters — Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 of Part II of this report. These credit ratings may not remain in effect for any given period of time and one or more of these ratings may be reduced or withdrawn by a rating agency. The Registrants note these credit ratings are not recommendations to buy, sell or hold their securities. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of the Registrants' credit ratings could have an adverse impact on their ability to access capital on acceptable terms. For example, if CERC's credit rating were to decline, it may have an adverse impact on the cost of borrowings and, in extraordinary market conditions, it may limit the ability to access the debt capital markets. Additionally, CERC might be required to post collateral under its shipping arrangements or to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when CERC was experiencing significant working capital requirements or otherwise lacked liquidity, CERC's business, financial condition, results of operations and cash flows could be adversely affected.

Changes in U.S. or foreign trade policies, including the imposition of tariffs and other trade actions, and other factors beyond our control may adversely impact our business, financial condition, results of operations and cash flows.

The U.S. government has taken executive action and proposed additional measures intended to alter the U.S. approach to international trade policy, the terms of certain existing bilateral or multi-lateral trade agreements and trading arrangements with foreign countries. Such changes to U.S. international trade policy, and retaliatory trade measures that foreign governments have taken and may take in the future in response, including the imposition of tariffs, bans, sanctions, export or import controls, or other measures that restrict international trade, or the threat of such actions, and uncertainties about tariffs and their effects on trading relationships, may affect, and in some cases have affected, the Registrants' ability to access the capital markets, contribute to inflation in the markets in which the Registrants operate, increase costs and cost volatility, impact availability of goods, materials and services (including those necessary for our business and capital plan), further extend lead times or otherwise negatively impact the global supply chain. While the U.S. government has announced various trade deals, many such agreements are preliminary and may be subject to change. Further, any future disagreement between the U.S. government and other countries over the implementation of trade deals or any failure to obtain required governmental approvals or otherwise reach a final agreement could result in prolonged uncertainty regarding the scope and duration of such trade actions by the U.S. government and other countries. Such announcements, rescissions of tariffs on foreign jurisdictions and other trade actions have increased uncertainty regarding the ultimate effects of the tariffs on economic conditions. In addition, related geopolitical and domestic political developments, such as existing and potential trade wars, uncertainty regarding changes in trade policy and other events beyond our control, have increased and may continue to increase levels of political and economic unpredictability globally and the volatility of global financial markets. Such developments could adversely affect our business, financial condition, results of operations and cash flows.

CenterPoint Energy is a holding company that derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. As a result, CenterPoint Energy depends on the performance of and distributions from its subsidiaries to meet its payment obligations and to pay dividends on its common stock, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.

CenterPoint Energy derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. Similarly, CERC derives a significant portion of its operating income from and holds a significant portion of its assets through its subsidiaries, including Indiana Gas and CEOH. As a result, CenterPoint Energy, and to a lesser extent, CERC, depend on the performance of and distributions from their respective subsidiaries to meet their respective payment obligations and to pay dividends on their respective common stock. In general, CenterPoint Energy's and CERC's subsidiaries are separate and distinct legal entities and have no obligation to provide them with funds for their respective payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit CenterPoint Energy's and CERC's respective subsidiaries' ability to make payments or other distributions to CenterPoint Energy or CERC, and their respective subsidiaries could agree to contractual restrictions on their ability to make payments or other distributions. Further, ring-fencing measures, such as those adopted by Houston Electric in connection with its 2019 base rate case, could be imposed on subsidiaries of CenterPoint Energy and CERC in the future through legislation or state commission rules or orders. The imposition of any additional measures impacting CenterPoint Energy's or CERC's ability to receive dividends from their respective subsidiaries could adversely affect CenterPoint Energy's credit quality, business, financial condition, results of operations and cash flows. Any such adverse effect on CenterPoint Energy could also adversely affect Houston Electric's and/or CERC's credit quality, business, financial condition, results of operations and cash flows as CenterPoint Energy may not be able to financially support Houston Electric and/or CERC if and when necessary.

CenterPoint Energy's right to receive assets of any subsidiary, and therefore the right of its creditors to participate in those assets, are structurally subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if CenterPoint Energy were a creditor of any subsidiary, its rights as a creditor would likely be effectively subordinated to any security interest in the assets of that subsidiary and any senior indebtedness of the subsidiary.

CenterPoint Energy's previously owned Energy Systems Group business has performance and warranty obligations, some of which are guaranteed by CenterPoint Energy.

On June 30, 2023, CenterPoint Energy closed the sale of its Energy Systems Group business. Prior to June 30, 2023 and as part of the normal course of its business, Energy Systems Group issued performance bonds and other forms of assurance that committed it to operate facilities, pay vendors or subcontractors and support warranty obligations. As the parent company prior to the closing of the sale, CenterPoint Energy or Vectren guaranteed certain of its subsidiaries' commitments. When Energy Systems Group was wholly owned by CenterPoint Energy, these guarantees did not represent incremental consolidated obligations, but rather, these guarantees represented guarantees of Energy Systems Group's obligations to allow it to conduct business without posting other forms of assurance. Neither CenterPoint Energy nor Vectren has been called upon to satisfy any

obligations pursuant to these parental guarantees to date but may be required to do so in the future. For further information, see Note 14(b) to the consolidated financial statements.

An impairment of goodwill, long-lived assets or equity method investments or a fair value adjustment could reduce our earnings.

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill is tested for impairment at least annually, as well as when events or changes in circumstances indicates the carrying value may not be recoverable. While CenterPoint Energy has identified and recorded goodwill impairments in the past, no impairments to goodwill were recorded during the years ended December 31, 2025, 2024, and 2023. See Note 6 to the consolidated financial statements for further information. Should the annual goodwill impairment test or another periodic impairment test or an observable transaction indicate the fair value of our assets is less than the carrying value, we would be required to take a non-cash charge to earnings with a correlative effect on equity, increasing balance sheet leverage as measured by debt to total capitalization. A non-cash impairment charge or fair value adjustment could adversely impact our business, financial condition, results of operations and cash flows.

If CenterPoint Energy redeems the ZENS prior to their maturity in 2029, its ultimate tax liability and redemption payments may result in significant cash payments, which would adversely impact its cash flows and liquidity. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity.

CenterPoint Energy has approximately \$828 million principal amount of ZENS outstanding as of December 31, 2025. CenterPoint Energy owns shares of ZENS-Related Securities equal to approximately 100% of the reference shares used to calculate its obligation to the holders of the ZENS. CenterPoint Energy may redeem all of the ZENS at any time at a redemption amount per ZENS equal to the higher of the contingent principal amount of less than \$0.1 million in the aggregate, or less than \$0.01 per ZENS, as of December 31, 2025, or the sum of the current market value of the reference shares attributable to one ZENS at the time of redemption. In the event CenterPoint Energy redeems the ZENS, in addition to the redemption amount, it would be required to pay deferred taxes related to the ZENS, to the extent such taxes were not currently offset by net operating loss carryforwards or CAMT carryforwards. CenterPoint Energy's ultimate tax liability related to the ZENS and ZENS-Related Securities continues to increase by the amount of the tax benefit realized each year. If the ZENS had been redeemed on December 31, 2025, deferred taxes of approximately \$897 million would have been payable in 2025, based on 2025 tax rates in effect, and disregarding the availability of net operating loss carryforwards and CAMT carryforwards. In addition, if all the shares of ZENS-Related Securities had been sold on December 31, 2025 to fund the aggregate redemption amount, capital gains taxes of approximately \$72 million would have been payable in 2025, disregarding the availability of net operating loss carryforwards and CAMT carryforwards. As of December 31, 2025, CenterPoint Energy had both net operating loss carryforwards and CAMT carryforwards available from its filed 2024 federal income tax return that can be applied to largely offset the cash tax outflow that would result from a retirement or exchange of ZENS. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity, subject to the availability of net operating loss carryforwards or CAMT carryforwards. This could happen if CenterPoint Energy's creditworthiness were to drop, the market for the ZENS were to become illiquid, or for some other reason. While funds for the payment of cash upon exchange of ZENS could be obtained from the sale of the shares of ZENS-Related Securities CenterPoint Energy owns or from other sources, ZENS exchanges result in a cash outflow because tax deferrals related to the ZENS and ZENS-Related Securities shares would typically be reversed when ZENS are exchanged and ZENS-Related Securities shares are sold, subject to the availability of net operating loss carryforwards or CAMT carryforwards to reduce the cash taxes payable in the year of exchange or sale.

Our potential business strategies and strategic initiatives, including merger and acquisition activities and the disposition of assets or businesses, may not be completed or perform as expected, adversely affecting our business, financial condition, results of operations and cash flows.

Our business, financial condition, results of operations and cash flows depend, in part, on our management's ability to implement our business strategies successfully and realize the anticipated benefits therefrom. In 2025, we announced our strategic goals for CenterPoint Energy, including our new 10-year capital plan. Our strategic goals are subject to the risks described in this section and various assumptions. These assumptions may require updating or we may not be able to execute on these strategic goals in a timely manner or at all. If we are unable to execute on our strategic goals, including our 10-year capital plan, the benefits therefrom may not be fully realized, if at all, and our reputation may be adversely affected.

From time to time we have made, and may continue to make, acquisitions or divestitures of, or other similar transactions involving, businesses and assets, such as our announced sale of our Ohio natural gas LDC business, Houston Electric's release

of its large TEEEF units to the San Antonio area and other potential future releasing and subleasing of TEEEF, form joint ventures or undertake restructurings, such as the Restructuring. However, suitable acquisition candidates or potential buyers may not continue to be available on terms and conditions we find acceptable, or the expected benefits of completed acquisitions, dispositions or similar transactions may not be realized fully or at all or may not be realized in the anticipated timeframe. If we are unable to make acquisitions, or if those acquisitions do not perform as anticipated, our future growth may be adversely affected. Further, any completed or future acquisitions, dispositions or other strategic transactions involve substantial risks, including the following:

- acquired businesses or assets, or other business strategies and strategic initiatives may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets, or other business strategies and strategic initiatives could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions, dispositions or other strategic transactions, or the pursuit of such transactions, including any separation or disentanglement efforts or requirements, such as the provision of transition services, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain current business standards, controls and procedures;
- we may not receive regulatory approvals necessary to complete an acquisition, disposition or similar transaction in a timely manner or at all; and
- shifting governmental policies may impact governmental support for strategic transactions.

On October 20, 2025, CenterPoint Energy, through its subsidiary CERC Corp., entered into the Ohio Securities Purchase Agreement to sell its Ohio natural gas LDC business. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements. We can make no assurances regarding the completion of this sale, which could be subject to delays or may not ultimately be consummated.

Changing demographics, poor investment performance of pension plan assets and other factors adversely affecting the calculation of pension liabilities could unfavorably impact our business, financial condition, results of operations and cash flows.

CenterPoint Energy and its subsidiaries maintain qualified defined benefit pension plans covering certain of its employees. Costs associated with these plans are dependent upon a number of factors including the investment returns on plan assets, the level of interest rates used to calculate the funded status of the plan, contributions to the plan, the number of plan participants and government regulations with respect to funding requirements and the calculation of plan liabilities. Funding requirements may increase and CenterPoint Energy may be required to make unplanned contributions in the event of a decline in the market value of plan assets, a decline in the interest rates used to calculate the present value of future plan obligations, or government regulations that increase minimum funding requirements or the pension liability. See Note 8 to the consolidated financial statements for further information. In addition to affecting CenterPoint Energy's funding requirements, these factors could adversely affect our business, financial condition, results of operations and cash flows.

We may be significantly affected by changes in federal income tax laws and regulations, including any comprehensive federal tax reform legislation.

Our businesses are impacted by U.S. federal income tax policy. The TCJA, CARES Act, the IRA and OBBBA significantly changed the U.S. Internal Revenue Code, including taxation of U.S. corporations, by among other things, reducing the federal corporate income tax rate, altering the expensing of capital expenditures, enacting a new CAMT, and phasing out previously expanded federal tax credits for cleaner energy production. Based on guidance available as of the date of the filing of this Form 10-K, the Registrants will continue to be subject to the CAMT included in the IRA.

The interpretive guidance issued by the IRS and state tax authorities, as well as related federal executive orders, may be inconsistent with our interpretation and the legislation could be subject to amendments, which could lessen or increase certain impacts of the legislation. In addition, while certain regulators have allowed the Registrants to recover certain costs associated with the CAMT in the past, the regulatory treatment of the expanded tax credits and CAMT could impact the Registrants' future

cash flows, and this legislation could result in unintended consequences not yet identified that could have an adverse impact on the Registrants' financial results and future cash flows.

Further changes in federal tax legislation or guidance, or uncertainties regarding the repeal, continuation or interpretation of such tax legislation or guidance, could significantly change the federal income tax laws applicable to domestic businesses, including changes that may impact investment incentives and deductions for depreciation and interest, among other deductions. Additional new federal tax reform legislation and the implementation of new or increased tariffs could lead to increases in market interest rates, a decrease in U.S. economic growth, and/or recession. In addition, interpretations, regulations, amendments, or technical corrections that affect the amount and timing of income tax payments could adversely affect our liquidity. While CenterPoint Energy and its subsidiaries cannot assess the overall impact of any such potential legislation or other actions on our businesses, it is possible that our business, financial condition, results of operations and cash flows could be negatively impacted. Furthermore, with any enacted federal tax reform legislation, it is uncertain how state commissions and local municipalities may require us to respond to the effects of such tax legislation, including determining the treatment of EDIT and other increases and decreases in our revenue requirements. As such, potential regulatory actions in response to any enacted tax legislation could adversely affect our business, financial condition, results of operations and cash flows.

Risk Factors Affecting Safety and Security Risks

The Registrants' businesses have safety risks.

The Registrants' facilities and distribution and transmission systems have been and may in the future be involved in incidents that result in injury, death, or property loss to employees, customers, third parties (including vendors, suppliers and contractors), or the public. Although the Registrants have insurance coverage for many potential incidents, depending upon the nature and severity of any incident, they have in the past and could in the future experience financial loss, claims and litigation, damage to their reputation, and negative consequences from regulatory authorities or other public authorities. Further, certain CenterPoint Energy employees who work in the field have experienced threats of violence during the performance of their work. Threats of violence, actual violence and other concerns may result in employees and third parties supporting the work of the Registrants sustaining serious injuries and being unable or unwilling to complete critical functions, which could adversely affect our businesses, financial condition, results of operations and cash flows, and could make it harder to, among other things, recruit and retain certain employees.

Cyberattacks, physical security breaches, acts of terrorism or other disruptions could adversely impact our business, financial condition, results of operations and cash flows.

We are subject to cyber and physical security risks related to our information technology systems, operational technology, network infrastructure and other technology and facilities used to conduct almost all of our businesses. The operation of our electric transmission, distribution and generation systems is dependent on the physical interconnection of our facilities, as well as communications among the various components of our systems and the systems of supply chain stakeholders (such as vendors, contractors and suppliers). Further, certain of the various internal systems we use to conduct our businesses are highly integrated. Consequently, a cyberattack or unauthorized access in any one of these systems could potentially impact the other systems. Similarly, our business operations, including our transmission systems and natural gas pipelines, are part of an interconnected system. Disruption of those systems, or our ability to communicate with those systems, whether caused by physical disruption such as storms or other natural disasters, by failure of equipment or technology or by man-made events, such as cyberattacks or acts of terrorism, may disrupt our ability to conduct operations and control assets, lead to operational interruptions and negatively impact our business.

The sophistication of cybersecurity threats, including those leveraging AI, continues to increase, and the controls and preventative actions we take to reduce the risk of cybersecurity incidents and protect our systems, including the regular testing of our cybersecurity incident response plan, may be insufficient. In addition, new technology that could result in greater operational efficiency, such as AI and cloud-based infrastructure, may further expose our computer systems to the risk of cybersecurity incidents. Also, remote working arrangements could increase our data security risks, including loss of data related to sensitive customer, employee, financial and operating system information, through insider or outsider actions. Cyberattacks, including deep fakes (which are increasingly more difficult to identify as fake), phishing, smishing, vishing or quishing attacks and threats from the use of malware, ransomware and viruses or malicious code, and unauthorized access could also result in the loss, or unauthorized use, of confidential, proprietary or critical infrastructure data or security breaches of other information technology systems that could disrupt operations and critical business functions, adversely affect our reputation, impact our customers, increase costs and subject us to possible legal claims and liability. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such

attacks, our cybersecurity program does not prevent all breaches or cyberattack incidents. Publicly known vulnerabilities in our information technology and operational technology environments may not be remediated before an adversary could discover or exploit them. Attackers can also exploit new, unknown vulnerabilities (e.g., zero-day vulnerabilities) and vulnerabilities where a patch or other remediation measure is not yet available. The data that we disclose to, and services we receive from, third parties may be subject to cybersecurity risks associated with threats to third-party systems. These risks include security compromises, vulnerabilities or failures related to the technologies and systems used by service providers, other supply chain stakeholders and/or governmental entities. The potential impact of such threats depends in part on the criticality of the third-party services and/or extent of access these third parties have to our confidential information and/or systems. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have also experienced, and expect to continue to experience, cyber intrusions and attacks to our information systems and those of third parties, including supply chain stakeholders and government entities who perform certain services for us or administer and maintain our sensitive information. These prior intrusions and attacks have not had a material impact on our business, financial condition, results of operations and cash flows. Because technology is increasingly complex and cyberattacks are increasingly sophisticated and more frequent, there is a risk such incidents could have an adverse effect on us in the future. The risk of a disruption or breach of our operational technology systems, or the compromise of the data processed in connection with our operations, through a cybersecurity breach or ransomware attack, has increased as attempted attacks have advanced in sophistication and number around the world. Although CenterPoint Energy currently maintains cybersecurity insurance, this insurance is limited in scope and subject to exceptions, conditions and coverage limitations and may not cover the costs associated with potential cybersecurity incidents, and there is no guarantee that the insurance that CenterPoint Energy currently maintains will continue to be available at rates we believe are reasonable.

Our continued efforts to integrate, consolidate and streamline our operations have also resulted in increased reliance on current and recently completed projects for technology systems and may increase potential vulnerabilities and points of failure in our information and operations systems. A failure to maintain and enhance existing information technology systems, or the failure of new technology systems to be implemented as designed, could adversely affect our operations. Procedures we implement to protect our systems may be insufficient to protect and safeguard against unauthorized access to secured data. A failure of our technologies or procedures, or our inability to support and integrate these technologies across our subsidiaries, could materially and adversely impact our operations, diminish customer confidence and our reputation, materially increase the costs we incur to protect against these risks and subject us to possible financial liability or increased regulation or litigation.

We depend on the secure operations of our physical assets to transport the energy we deliver and our information technology to process, transmit and store electronic information, including information and operational technology we use to safely operate our energy transportation systems. Companies in our industry face a heightened risk of exposure to and have experienced acts of terrorism and vandalism. Our electric and gas physical infrastructure may be targets of physical security threats or terrorist activities. Further, recent escalation with respect to geopolitical conflicts may increase the likelihood that facilities within the United States, including natural gas distribution systems or electric transmission, distribution or generation systems that we own or on which we rely, will be targeted by strikes, acts of terrorism or cyberattacks. Security breaches, attacks on our infrastructure and facilities, including against the Registrants or as a means to harm a third party by disrupting the transmission and distribution of energy, acts of terrorism, including by foreign or domestic actors, and vandalism could expose our business to a risk of loss, misuse or interruption of critical physical assets or information and functions that affect our operations, as well as potential data privacy breaches and loss of protected personal information and other sensitive information, such as Critical Energy Infrastructure Information. Such losses could result in operational impacts, damage to our assets, public or personal safety incidents, impacts to our customers, damage to the environment, reputational harm, competitive disadvantage, increased regulation and regulatory enforcement actions, litigation and a potential adverse effect on our business, financial condition, results of operations and cash flows. There is no certainty that costs incurred related to actual or thwarted cyberattacks, or for the safeguarding against such security threats, will be recoverable through rates.

Compliance with and changes in cybersecurity laws and regulations have a cost and operational impact on our business, and failure to comply with such requirements could adversely impact our business, financial condition, results of operations and cash flows.

Regulators have adopted numerous rules and regulations regarding cybersecurity. As a result, CenterPoint Energy continues to take measures to comply with the TSA pipeline security directive requirements applicable to critical pipeline owners and operators. These security directives require CenterPoint Energy to establish, implement and assess a TSA-approved Cybersecurity Implementation Plan that describes the security measures maintained to comply with relevant provisions of the security directives. CenterPoint Energy is also subject to standards enacted by NERC and enforced by FERC regarding protection of critical infrastructure assets required for operating North America's bulk electric system. We may be required to expend significant additional resources and costs to respond to cyberattacks, to continue to modify or enhance our protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. There is no certainty that

such costs incurred will be recovered through rates. We also face increasing and evolving disclosure and reporting obligations related to cybersecurity events, and there is no certainty that we will be able to meet existing or future disclosure obligations and avoid the risk of potentially having our disclosures misinterpreted when made. National security or public safety considerations may further affect, or in some instances prevent, our public disclosure of a cybersecurity incident in certain circumstances. Any failure to remain in compliance with these government regulations or failure in our cybersecurity protective measures may result in enforcement actions which may have an adverse effect on our business, financial condition, results of operations and cash flows.

Failure to maintain the security of personal information could adversely affect us.

In connection with our businesses, we and supply chain stakeholders collect and retain personal information (for example, information of our customers, shareholders, suppliers and employees), and there is an expectation that we and such supply chain stakeholders will adequately protect that information. The regulatory environment surrounding information security and data privacy continues to evolve and is increasingly demanding. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and elevate our costs. Any failure by us to comply with these laws and regulations, including as a result of a security or privacy breach, could result in significant costs, fines and penalties and liabilities for us. The systems we have implemented to protect our information technology, operational technology and data systems from attacks cannot prevent all security breaches, and the systems we have implemented to manage and protect personal information cannot prevent all privacy breaches. We and some supply chain stakeholders that maintain personal information have experienced, and expect to continue to experience, data privacy incidents and breaches; however, to date, we have not experienced a material data privacy incident or breach. A significant theft, loss or fraudulent use of the personal information we maintain, or failure of our vendors, suppliers and contractors to use or maintain such data in accordance with contractual provisions and other legal requirements, could adversely impact our reputation and could result in significant costs, fines and penalties and liabilities for us.

We may not be successful in our adoption, development and deployment of AI, which could adversely affect our business, reputation, or financial results.

We are using and exploring the further use of AI, including generative AI, and its ability to enhance the services we offer to the communities we serve. There are significant risks involved in developing and deploying AI, and ineffective or inadequate development or deployment of AI practices by us or supply chain stakeholders could result in unintended consequences. We contract with supply chain stakeholders that use AI in products and services they provide, and we may not have full control or visibility over the quality, performance, security or compliance of the products and services that incorporate AI-related technology. Additionally, the use of AI may not enhance our services or be beneficial to our business, including with respect to the efficiency and resiliency of our systems. For example, AI-related efforts by us or supply chain stakeholders may give rise to risks related to harmful content, accuracy, bias, discrimination, intellectual property infringement or misappropriation, defamation, data privacy, and cybersecurity, among others, which could lead to operational interruptions or otherwise adversely affect our business, reputation or financial results. In addition, the adoption of AI may subject us to new or enhanced governmental or regulatory scrutiny, new or amended laws, rules, directives, and regulations governing the use of AI (which may be conflicting), litigation, ethical concerns, negative consumer perceptions as to automation and AI, or other complications that could adversely affect our business, reputation, or financial results. Developing, testing and deploying resource-intensive AI systems may also require additional investment and increase costs. We may not be able to recover our investments in AI technology through our regulatory proceedings, and our use of, or supply chain stakeholders' use of, AI may subject us to legal liability. Similarly, as AI continues to evolve, we may not be able to adopt and implement AI as quickly as our customers or communities desire or regulators may require, which could also adversely affect us. AI is a relatively new and rapidly evolving technology, and we are unable to predict all of the risks that may result from the adoption of our AI initiatives.

General and Other Risks

Our revenues and results of operations are seasonal.

Our revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity and natural gas usage, as applicable. Houston Electric's revenues are generally higher during the warmer months. As in certain past years, unusually mild weather in the warmer months could diminish Houston Electric's results of operations and harm its business, financial condition and cash flows. Conversely, as in certain past years, extreme warm weather conditions could increase Houston Electric's results of operations in a manner that would not likely be annually recurring. A significant portion of Indiana Electric's sales are for space heating and cooling. Consequently, as in certain past years, Indiana Electric's results of operations may be adversely affected by warmer-than-normal heating season weather or colder-than-normal cooling season weather, while, as has occurred in certain past years, more extreme seasonal weather conditions could increase Indiana

Electric's results of operations in a manner that would not likely be annually recurring. Revenues in our Natural Gas reportable segment are customarily higher during the winter months. As in certain past years, unusually mild weather in the winter months could diminish our results of operations and harm our business, financial condition, results of operations and cash flows. Conversely, as occurred in certain past years, extreme cold weather conditions could increase our results of operations in a manner that would not likely be annually recurring.

Severe weather events, natural disasters and other climate-related impacts could adversely impact our businesses, financial condition, results of operations and cash flows.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to our service territories and our business. Our facilities and operations face physical risks from severe weather events, natural disasters and other climate-related conditions, which have become more frequent, unpredictable and severe as a result of climate change or other factors. Severe weather events, natural disasters and other climate-related conditions impact our service territories, primarily when hurricanes and remnants of hurricanes, tornadoes, floods, severe winter weather conditions, including ice storms, wildfires, thunderstorms, high winds, hail, derecho events, microbursts, drought, excess humidity or extreme temperatures (high heating/cooling days) occur, which can impact our operations and our ability to serve our customers, including resulting in operational interruptions and large-scale and/or prolonged outages. To the extent the frequency and severity of extreme weather events, natural disasters and climate-related conditions such as rising sea level and coastal erosion continue to increase, our costs of providing service may increase, including the costs and availability of procuring insurance related to such impacts, and those costs may not be recoverable. In addition, our insurance may not be sufficient or effective under all circumstances and against all related hazards or liabilities to which we may be subject. Any losses for which we are not fully insured or that are not covered by insurance at all could adversely affect our business, financial condition, results of operations and cash flows. A delay or failure in recovering amounts for storm restoration costs incurred, inability to securitize future storm restoration costs, or loss of revenues as a result of severe weather could have a material impact on us, including lower credit ratings and, thus, higher costs for future debt issuances, as well as limitations on our ability to fund other investments to address customer needs. The implementation of budget and spending cuts to federal government agencies and programs could also impact our operations and our ability to serve customers when such weather events, natural disasters and other climate conditions occur, including increasing our costs. Further, events of extreme weather and natural disasters could make it unsafe or hinder the effectiveness of our employees to fix, maintain and restore power to affected areas and could harm our reputation. Since certain of our facilities are located along or near the Texas Gulf Coast, increased or more severe hurricanes, tornadoes or derecho events could increase our costs to repair damaged facilities and restore service to our customers. Our electric and natural gas operations in our service territories have both been impacted by severe weather events, including the February 2021 Winter Storm Event, the May 2024 Storm Event and Hurricane Beryl, and could experience similar events in the future, which could have an adverse impact on our business, financial condition, results of operations and cash flows. Further, if climate changes occur that result in fewer heating degree days than normal in our service territories, which has occurred in certain past years, financial results from our businesses could be adversely impacted. For example, where natural gas is used to heat homes and businesses, warmer weather might result in less natural gas being used, adversely affecting us.

Severe weather events, natural disasters and the effects of climate change have increased the duration of wildfire season and may further exacerbate the possibility of wildfires and the risks related thereto, including that we may be held liable for damages incurred as a result of wildfires, reputational harm, damage to our network, facilities and systems resulting therefrom. While we proactively take steps to mitigate wildfire risk in the areas of our electrical and natural gas assets, wildfire risk is always present. We could be held liable for damages incurred as a result of wildfires or incur reputational harm if it was determined that they were caused by or enhanced due to any fault of CenterPoint Energy. Wildfires could also jeopardize our electric and natural gas infrastructure, including Houston Electric's and Indiana Electric's vast network of electric transmission and distribution lines and facilities and CERC's natural gas distribution systems, and third-party property and result in temporary or prolonged power outages and shortages in our service territories. Wildfires also have the potential to negatively affect communities in our service territories and the surrounding areas, and the continued expansion of the wildland-urban interface has increased this wildfire risk. In addition, while we maintain wildfire insurance, our insurance may not be sufficient to cover all losses we may incur as a result of wildfires. Wildfires could also lead to significant financial distress, credit rating downgrades and further increased costs for wildfire insurance or lack of availability thereof. Insufficient wildfire insurance coverage, increased wildfire insurance costs and a lack of wildfire insurance availability could adversely impact our business, financial condition, results of operations and cash flows. Furthermore, any damage caused to our assets, loss of service to our customers, liability imposed, credit rating downgrades or regulatory recovery risk occurring as a result of wildfires could negatively impact our business, financial condition, results of operations and cash flows.

We are subject to transition risk relating to climate change, as well. In the long term, climate change could cause shifts in population, including customers moving away from our service territories. When we cannot deliver electricity or natural gas to

customers or our customers cannot receive our services, our financial results are impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs or recover in a timely manner, or if recovery of such costs results in higher rates and reduced demand for our services, our future financial results may be adversely impacted. Similarly, public and private efforts to address climate change, such as by legislation, regulation, actions by private interest groups, and litigation, could impact our ability to continue operating our businesses as we do today, significant aspects of which rely on fossil fuels. These initiatives could have a significant impact on us and our operations as well as on our third-party suppliers, vendors and partners, which could impact us by among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to us. We also may be subject to climate change litigation, which could result in substantial fines, penalties or damages and restrictions on our operations. The utility industry has already faced such litigation, challenging its marketing and use of fossil fuels and attributing climate change to emissions resulting from the use of fossil fuels. While we have pursued and executed, and continue to pursue and execute, on plans to accelerate investments to enhance the resiliency of our systems to better withstand severe weather, natural disasters, and other climate-related impacts, these plans are generally subject to approval by regulators and may not be approved in full or at all. Certain accelerated resilience plans of the Registrants have received regulatory approval for a limited scope and duration, generally at levels less than those proposed to the regulators. We may not be able to successfully execute such plans and projects in the time and manner planned and there are risks regarding the ability to demonstrate the efficacy of the accelerated resilience investments in mitigating storm impacts, as well as in seeking and obtaining regulatory approval for additional accelerated resilience plans and projects that may be necessary. The need for this investment and these expenditures could cause execution, liquidity, capital or other financing-related risks as well as result in upward pressure on our customer rates, which, particularly when combined with upward pressure resulting from the recovery of the costs of recent and future storms, may result in adverse actions by applicable regulators or effectively limit our ability to make other planned capital or other investments. The occurrence of extreme weather events, including winter storms and record hot temperatures, or other causes could also lead to additional reforms to the Texas electric market, some measure of which, if implemented, could have an adverse impact on Houston Electric. For example, during and in the aftermath of the February 2021 Winter Storm Event, the Texas legislature revised applicable statutes and granted the PUCT and ERCOT additional regulatory authority, both oversight and enforcement, that focuses on ensuring ERCOT market participants, including Houston Electric, have adopted sufficient winterization standards and protection. If any additional protections are required in the future as a result of additional extreme weather events or other causes, complying with these new protections may increase the cost of electricity, which could adversely affect Houston Electric's business, financial condition, results of operations and cash flows.

We are exposed to risks related to changes in demand and energy consumption that could adversely impact our business, financial condition, results of operations and cash flows.

Our businesses are also affected by new customers and load growth. We anticipate a high level of load growth and an increase in demand for electric power in certain of our service territories, including from the expansion of data centers (associated with, among other things, increasing demand for AI), energy refining and exports, advanced manufacturing and logistics, and a significant portion of the planned investments in our 10-year capital plan is intended to support such expected growth. Nevertheless, significant uncertainty exists. We are subject to potential challenges in accurately forecasting such load growth and predicting future electric power needs due to, among other things, rapidly changing technology and market dynamics, changes in industry practice and the possibility that new large customers will be transitory and exit our service territory or otherwise delay or cancel their planned projects. We are subject to potential challenges in capitalizing on opportunities presented by these developments (including if such opportunities do not materialize to the degree expected), managing the potential power demand, generation sources, and transmission capabilities to meet potential load growth, financing the capital investment needed to build and maintain the necessary infrastructure to support such development on satisfactory terms and conditions and consistent with the maintenance of satisfactory credit ratings, executing on such build and maintenance of the necessary infrastructure to support such development on acceptable timelines and in a cost-effective manner while maintaining affordability for customers, managing the possible environmental impact of the potential increased power demand, achieving our energy transition goals on expected timelines and evaluating and complying with evolving regulations related to such development. These challenges, and our efforts to predict and address them, could have a material impact on us, including if we fail to capitalize on the opportunities relating to these developments or fully realize anticipated benefits from significant capital investments and expenditures made to address such development, which could adversely affect our ability to execute our 10-year capital plan, cause us to incur additional expenses to terminate or redeploy any underutilized assets or infrastructure, or fail to fully recover our capital expenditures, all of which could have an adverse effect on our business, financial condition, results of operations and cash flows. For example, our failure to capitalize on the opportunities presented by these developments or potential large load customers delaying or cancelling their planned projects could lead to delays or the cancellation of projects included in our 10-year capital plan. Further, regulators may investigate the prudence of costs in our rates and examine, among other things, the reasonableness or prudence of our level of expenditures (including costs associated with our capital projects supporting new customers and load growth). In addition, volatility in stock prices of perceived significant energy customers, such as technology companies involved with data centers, AI or cryptocurrency, or other

significant developments with such companies, could cause increased volatility in stock prices of certain companies in our industry.

Higher electric power demand and load growth could also significantly increase the prices of energy and capacity, which could in turn affect customer rates or be perceived to affect customer rates and raise affordability concerns, as well as raise resource adequacy and reliability concerns, particularly if that increased demand outpaces the addition of firm generation capacity and in transmission constrained zones. For example, there has been increasing media attention and public claims regarding the link between large load customers such as data centers and increased customer bills. Increased customer rates or the perception that customer rates are increasing to address large load customers could attract political and regulatory scrutiny, increase regulatory uncertainty for our capital investment plans and programs and present reputational risks. Additionally, projected load growth across the ERCOT system could, if not sufficiently addressed through system design and reliability measures, negatively impact electric infrastructure reliability and potentially cause system-wide stresses. This resource adequacy challenge presents reliability concerns, as well as potential for increasing energy and capacity prices that could place pressure on customer bills, attract political and regulatory scrutiny, increase regulatory uncertainty for our capital investment plans and programs and present reputational risks. These matters could have an adverse effect on our business, financial condition, results of operations and cash flows.

Our businesses are also affected by reduction in energy consumption due to factors including economic, climate and market conditions in our service territories, energy efficiency/reduction initiatives, advances in technology and use of alternative technologies and changes in our customers' perceptions regarding natural gas usage as a result of incidents of other utilities involving natural gas pipelines, which could impact our ability to grow our customer base and our rate of growth. Growth in customer accounts and growth of customer usage each directly influence demand for electricity and natural gas and the need for additional delivery facilities. Customer growth and customer usage are affected by a number of factors outside our control, such as energy efficiency/reduction initiatives, bans on or further regulation of natural gas-fired appliances, demand-side management goals, technological advances (e.g., distributed generation resources, energy storage devices and more energy efficient buildings and products) and economic and demographic conditions, including population changes, job and income growth, housing starts, changes in rate designs, new business formation and the overall level of economic activity. For example, certain regulatory and legislative bodies have introduced or are considering requirements and incentives to reduce energy consumption by certain dates. Declines in demand for electricity and natural gas in our service territories due to pipeline incidents of other utilities, increased electricity and natural gas prices as experienced during the February 2021 Winter Storm Event and during periods of persisting high inflation or economic downturns, among other factors, could reduce overall usage and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and natural gas. Although Houston Electric's and Indiana Electric's transmission and distribution businesses are subject to regulated allowable rates of return and recovery of certain costs under periodic adjustment clauses, overall declines in electricity delivered and used as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. A reduction in the rate of economic, employment and/or population growth could result in lower growth and reduced demand for and usage of electricity and natural gas in such service territories. Additionally, certain laws in our service territories allow municipalities to create, own, and operate utilities. If one or more municipalities in our service territories create new or supplemental utilities, or impair the franchises under which we serve customers in the applicable municipalities, it could result in lower growth and reduced demand for and usage of electricity and natural gas in such service territories. Further, deregulation or other changes in law in our service territories could allow third-party suppliers to contract directly with customers for their natural gas and electric supply requirements. In addition, legislation or regulation that supports distributed energy technologies or that allows third party sales from such technologies could result in further competition. Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or natural gas or number of customers and may result in our failure to fully realize anticipated benefits from significant capital investments and expenditures, which could have an adverse effect on our business, financial condition, results of operations and cash flows.

Aging infrastructure may lead to increased costs and disruptions in operations that could negatively impact our financial results.

We have risks associated with aging infrastructure assets, including the failure of equipment or processes and potential breakdowns due to such aging. These risks have in the past and may continue to be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal and external corrosion, ground movement and stress corrosion and/or cracking. The age of certain of our assets, including each of Indiana Electric's coal generating facilities, which were constructed in 1973 and 1966, respectively, have in the past resulted and may continue to result in a need for replacement, higher level of maintenance costs, reduced generation output and unscheduled outages because of, among other things, our risk-based federal and state compliant integrity management programs. The failure to operate our assets as desired could result in interruption of service, safety concerns, major component failure at generating facilities and electric substations, events such as gas leaks, and an inability to meet service and compliance obligations, which could adversely impact revenues, and could also result in increased

capital expenditures and maintenance costs. As part of our capital plan and various plans and projects thereunder, we continue to make upgrades to our aging infrastructure assets to enhance the reliability of our infrastructure. Failure to achieve timely and full recovery of expenses associated with our aging infrastructure could adversely impact revenues and could result in increased capital expenditures or expenses. In addition, the nature of information available on aging infrastructure assets, which in some cases is incomplete, may make operation of the infrastructure, inspections, maintenance, upgrading and replacement of the assets particularly challenging. Missing or incorrect infrastructure data may lead to difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues; configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures; and other potential risks related to missing or incorrect infrastructure data. Also, additional maintenance and inspections are required in some instances to improve infrastructure information and records and address emerging regulatory or risk management requirements, resulting in increased costs.

Our ability to successfully maintain or replace our aging infrastructure has been and may continue to be delayed or be at a greater cost than anticipated due to supply chain issues or governmental actions. For example, while Indiana Electric's 2025 IRP (similar to previous IRPs) preferred portfolios included the retirement of F.B. Culley Unit 2 by the end of 2025, a coal-fired generation unit, the U.S. Department of Energy issued emergency order 202(c) in December 2025 directing Indiana Electric to continue operating the unit through March 23, 2026. Additionally, with respect to our natural gas operations, if certain pipeline replacements (for example, cast-iron or bare steel pipe) are not completed timely or successfully, government agencies and private parties might allege the uncompleted replacements caused events such as fires, explosions or leaks. Although we maintain insurance for certain of our facilities, our insurance coverage may not be sufficient in the event a catastrophic loss is alleged to have been caused by a failure to timely complete equipment replacements. Insufficient insurance coverage and increased insurance costs could adversely impact our business, financial condition, results of operations and cash flows. Finally, aging infrastructure may complicate our utility operations ability to address severe weather, natural disaster and climate change concerns and efforts to enhance resiliency and reliability.

Our business, financial condition, results of operations and cash flows may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance depends on the successful operation of our facilities. Operating these facilities involves many risks inherent in the transmission, distribution and generation of electricity and in the delivery of natural gas that could result in substantial losses or other damages. From time to time, we have and may in the future experience various risks associated with the operations of our facilities, including, but not limited to, the following:

- operator error or failure of equipment or processes, including natural gas ignition events or associated incidents, pipeline high-pressure or over-pressure events or ruptures, or failure to follow appropriate safety protocols for, among others, the transmission and distribution of electricity and in the delivery of natural gas, including operations of our storage and peak shaving facilities;
- the handling of hazardous equipment or materials that could result in serious personal injury, loss of life and environmental and property damage;
- the inability to maintain the reliability of our utility services or meet generation capacity obligations;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- information technology or financial and billing system failures, including those due to the implementation and integration or failure of new technology (including AI technology), that impair our information technology infrastructure, reporting systems or disrupt normal business operations, affect our ability to access customer information or cause us to lose confidential or proprietary data that adversely affects our reputation or exposes us to legal claims;
- regulatory noncompliance, compliance mandates and penalties from our regulators;
- failure to obtain in a timely manner and at reasonable prices the necessary fuel, such as coal and natural gas, building materials or other items needed to operate our facilities; and
- catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, tornados, derecho events, ice storms, terrorism, cybersecurity incidents, wildfires, public health emergencies (including pandemics), acts of war, military invasions, civil unrest, geopolitical conflict or other similar occurrences, including any environmental impacts related thereto, which catastrophic events may require participation in mutual assistance efforts by us or other utilities to assist in power restoration efforts, and for which our emergency preparedness plans may not be adequate or we may not respond effectively, which could result in public or employee harm.

Such events may result in a decrease or elimination of revenue from our facilities, an increase in the cost of operating our facilities, environmental or property damage, delays in cash collections, harm to our reputation, legal proceedings, less favorable legislative and regulatory outcomes, changes to policies, laws and regulations or increased regulatory oversight, any of which could have an adverse effect on our business, financial condition, results of operations and cash flows. Such events have and may in the future result in the imposition of regulatory or environmental fines and increased litigation.

Our businesses will continue to have to adapt to, integrate and implement technological change and may not be successful implementing such technological change as designed or may have to make significant investments to adapt to and integrate technological change.

We operate businesses that require sophisticated data collection, processing systems, software and other technology. Some of the technologies supporting the industries we serve are changing rapidly and increasing in complexity. New technologies will emerge or evolve that may deliver superior capabilities to, or may not be compatible with, some of our existing technologies, and may require us to make significant investments so that we can continue to provide cost-effective and reliable technology solutions to support energy production and delivery. Our future success will depend, in part, on our ability to anticipate, adapt to, integrate and implement technological changes in a timely and cost-effective manner, to offer, on a timely basis, reliable services that meet customer demands and evolving industry standards and to recover all, or a significant portion of, any unrecovered investment, including obsolete assets. Accordingly, we periodically implement new or enhanced technology, including information systems. Implementation of such new technology, including information systems, can, and pursuant to certain projects included in our 10-year capital plan, will, require the commitment of significant, sufficiently skilled personnel, engagement of third parties, substantial capital investment and additional administration and operating expenses, and entails risks to our business operations. If the integration or implementation of technology, including information systems, as designed is delayed or unsuccessful, we may not realize anticipated productivity improvements or cost efficiencies and may experience interruptions in service and operational difficulties, which could adversely affect our business, financial condition, results of operations and cash flows. Our 10-year capital plan additionally calls for the rapid integration and implementation of new technologies such as advanced grid infrastructure, which increases exposure to potential grid instability and technology obsolescence. If we fail to successfully adapt to, integrate and implement a technological change, fail to obtain access to important technologies, incur significant expenditures in adapting to technological change, or if implemented technology does not operate as anticipated, our regulatory recovery could be negatively impacted and our businesses, financial condition, results of operations and cash flows could be adversely affected.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our business, financial condition, results of operations and cash flows.

We currently have insurance in place, such as general liability, excess liability and property insurance, to cover, among other things, certain of our facilities and third-party bodily injury in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage premiums continue to increase, and insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to fully cover or restore the loss or damage without negative impact on our business, financial condition, results of operations and cash flows. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been in the past and may in the future be excluded under the policies. In addition, insurers providing insurance to us have in the past and may in the future dispute and raise defenses to coverage under the terms and conditions of the respective insurance policies, which can result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could adversely affect our business, financial condition, results of operations and cash flows. Costs, damages and other liabilities related to recent events and incidents that affected other utilities, such as wildfires, winter storms and explosions, among other things, have exceeded or could exceed such utilities' insurance coverage. Further, as a result of these recent events and incidents, the marketplace for insurance coverage to utility companies may be unavailable or limited in capacity or any such available coverage may be deemed by us to be cost prohibitive under current conditions. Insurance premiums for any such coverage, if available, may not be eligible for recovery, whether in full or in part, by us through the rates charged by our utility businesses.

In common with other companies in its line of business that serve coastal regions, Houston Electric does not have insurance covering its transmission and distribution system, other than substations, because Houston Electric believes it to be cost prohibitive and insurance capacity to be limited. Historically, Houston Electric has been able to recover the costs incurred in restoring its transmission and distribution properties following hurricanes or other disasters through issuance of storm restoration bonds or a change in its regulated rates or otherwise. In the future, any such recovery may not be granted. For

example, Houston Electric is seeking to recover the system restoration costs associated with Hurricane Beryl and certain other significant storms through the issuance and sale of non-recourse system restoration bonds. Although Houston Electric expects to receive the net proceeds from its offering of system restoration bonds on February 26, 2026, there can be no assurance that the system restoration costs will be recovered in the amounts expected or on the expected timeline. Therefore, Houston Electric may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its business, financial condition, results of operations and cash flows.

Global or regional health pandemics, epidemics or similar public health threats could negatively impact our business, financial condition, results of operations and cash flows.

Public health threats, including pandemics and epidemics, and any third-party actions taken to contain the spread and mitigate the public health threats, have had and may in the future have widespread impacts on the global economy, our supply chain and our employees, customers and supply chain stakeholders. Any future health threat could have potentially material impacts on our business, financial condition, results of operations and cash flows. The ultimate impact of public health threats on our business depends on factors beyond our knowledge or control and we might not be able to predict or respond to all impacts on a timely basis to prevent near- or long-term adverse impacts to our business, financial condition, results of operations and cash flows.

Failure to attract, motivate and retain an appropriately qualified workforce, identify and develop top talent to succeed senior management and maintain good labor relations could adversely impact the operations of our facilities and our business, financial condition, results of operations and cash flows.

Our businesses and ability to implement our strategies are dependent on recruiting, retaining and motivating employees, including senior executive officers and other key personnel. Like many companies in the utilities industry and other industries, we have experienced higher than normal turnover of employees as a result of a number of factors, including a tightening labor market, remote working opportunities, employees shifting industries, individuals deciding not to work and a maturing workforce. Of our employee population, not including employees of Energy Systems Group prior to its divestiture on June 30, 2023 or temporary employees, 17.1%, 18.2%, and 18.7% were retirement eligible as of December 31, 2025, 2024, and 2023, respectively. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skillsets to future needs, increased turnover or the unavailability of contract resources, may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Our costs, including costs to replace employees, productivity costs, health care costs and safety costs, may rise and may not be recoverable in rates. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of sufficiently skilled contract labor may lead to safety concerns and adversely affect the ability to manage and operate our businesses, particularly the specialized skills and knowledge required to construct and operate generation facilities, a technology-enabled power grid and transmission and distribution infrastructure, among other facilities. Additionally, further tightening of the labor market and increasing wages may adversely affect our ability to attract, transition and retain key personnel, which could, in turn, negatively impact our ability to identify, motivate and develop talent to succeed senior management. If we are unable to successfully attract and retain an appropriately qualified workforce and conduct appropriate senior management succession planning, our ability to execute on our 10-year capital plan and our business, financial condition, results of operations and cash flows could be negatively affected.

Furthermore, the operations of our facilities depend on good labor relations with our employees, and several of our businesses have in place collective bargaining agreements with various labor unions, comprising approximately 42% of our workforce. We have several separate bargaining units, each with a unique collective bargaining agreement described further in Note 8(j) to the consolidated financial statements, which information is incorporated herein by reference. The collective bargaining agreements with IBEW Locals 1393 and USW Locals 12213 & 7441 related to Indiana Gas employees, as well as with IBEW Local 66 related to Houston Electric employees, are scheduled to expire in December 2026 (IBEW Local 1393 & USW Locals 12213 & 7441) and May 2026 (IBEW Local 66), and negotiations of these agreements are expected to be completed before the respective expirations. The collective bargaining agreement with OPEIU Local 12 related primarily to CERC employees in Minnesota expired in December 2025 and negotiations are ongoing. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. These potential labor disruptions could have an adverse effect on our businesses, financial condition, results of operations and cash flows. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have an adverse effect on our businesses, financial condition, results of operations and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Our processes for assessing, identifying, and managing material risks from cybersecurity threats are part of our overall enterprise risk management system and processes. Enterprise risks, including cybersecurity risks, and their associated mitigations are reviewed at least annually by senior management and the Board. Throughout the year, we regularly assess our cybersecurity program and continue to invest in hardening and maturing our cybersecurity measures as further described below.

Risk Management Strategy and Processes

We maintain a cybersecurity program to help us assess, identify, and manage cybersecurity risks to our systems and data, including to help us defend against and mitigate emerging and existing cybersecurity threats to our information technology and operational technology systems. Our strategies and processes for managing cybersecurity risks are informed by relevant industry frameworks and laws, regulations and standards applicable to us in the jurisdictions in which we do business, including those applicable to utilities that operate bulk electric systems or critical pipeline facilities. We maintain various policies, procedures, technologies and other controls to help prevent, detect, mitigate and manage cybersecurity threats and incidents. We also use third-party consultants and service providers to support our risk management efforts, such as services for cybersecurity intelligence, monitoring, testing and assessments.

Key aspects of our risk management processes include:

- **Threat Monitoring.** We receive information on emerging cybersecurity threats and vulnerabilities from different sources, including vendors, cybersecurity organizations and U.S. government agencies, to help support our ability to detect and defend against threats to the security of our information technology and operational technology systems. We maintain several cybersecurity monitoring tools and services to help us detect unauthorized activities involving our systems and potential cybersecurity threats and vulnerabilities to our systems.
- **Incident Response.** We maintain a Cybersecurity Operations Center that is dedicated to monitoring for cybersecurity threats to our systems and responding to potential cybersecurity incidents. We also maintain cybersecurity incident response plans that establish a cross-functional incident response team and processes to guide our response to cybersecurity incidents, including processes for reporting and escalating cybersecurity incidents to senior management and the Audit Committee or the Board, as appropriate. We conduct tabletop exercises regularly to test our incident response processes.
- **Assessments, Testing and Audits.** We conduct different types of security assessments, testing and audits to help us proactively identify and mitigate potential cybersecurity threats and vulnerabilities to our information technology and operational technology systems. For example, we conduct security-related risk assessments on proposed software, hardware and third-party technology solutions used by CenterPoint Energy prior to deployment in our network. We also undergo periodic vulnerability assessments, penetration tests and cybersecurity reviews of our systems and security controls. We engage third parties to support certain of these assessments and tests and to provide guidance and support to our cybersecurity management team. Our internal audit team also conducts audits of certain CenterPoint Energy systems and data security controls.
- **Third-Party Risk Management.** We maintain a vendor risk management program, a component of which assesses the cybersecurity and data privacy practices of certain third-party service providers to help us assess and manage cybersecurity risks associated with third-party access to our systems and data. To help identify and mitigate third-party cybersecurity risks, we conduct vendor security reviews and privacy impact assessments when deemed appropriate based on the nature of the systems and data that will be accessed by the third-party. We also impose contractual obligations on certain of our service providers related to data privacy, confidentiality and security based on, among other factors, their extent of access to our data and systems and the nature and sensitivity of the data and systems to which they have access.
- **Training and Awareness.** We hold regular employee trainings on privacy, cybersecurity, AI and records and information management, conduct simulated phishing tests, and generally seek to promote awareness of cybersecurity risk through communication and education of our employee population.

As described in Item 1A “Risk Factors,” our operations rely on the secure processing, storage, and transmission of confidential, sensitive and other information within our computer systems and networks. Computer viruses, threat actors, employee or vendor incidents and other external hazards could expose our information systems, and those of third parties who process our data, provide access to systems or that have access to our systems, to security breaches, cybersecurity incidents or other disruptions, any of which could materially and adversely affect our business, reputation, results of operations and financial condition, and subject us to possible legal claims and liability. While we have experienced cybersecurity incidents in the past, as of the date of the filing of this Form 10-K, CenterPoint Energy has not identified any cybersecurity threats that have materially affected or are reasonably anticipated to have a material effect on us, including our business strategy, results of operations, or financial condition.

Governance

Board of Directors Oversight

Our Audit Committee, comprised of independent directors from our Board, oversees the Board’s responsibilities relating to CenterPoint Energy’s cybersecurity, data privacy and AI programs, including cybersecurity and AI risk management and cybersecurity disclosures required by applicable securities laws or regulations, as appropriate. As part of its risk oversight responsibilities, the Audit Committee receives quarterly reports from our Executive Vice President and General Counsel, Chief Security Officer (CSO) or other representatives from our cybersecurity or data privacy groups and periodic reports from our third-party consultants. These reports include updates on certain cybersecurity or data privacy matters, including, among other items, CenterPoint Energy’s progress in maturing its cybersecurity program, results of cybersecurity assessments and testing, the cybersecurity landscape and emerging threats, status of ongoing initiatives and strategies, incident reports and learnings from any cybersecurity events, compliance with regulatory requirements and industry standards, data privacy matters, and the cybersecurity budget.

Risk Management Personnel

CenterPoint Energy’s Executive Vice President and General Counsel is responsible for overseeing our cybersecurity and data privacy programs. CenterPoint Energy’s CSO is responsible for the day-to-day management of our cybersecurity program and reports directly to the Executive Vice President and General Counsel. CenterPoint Energy’s Senior Vice President, Deputy General Counsel, and Chief Ethics & Compliance Officer (CECO) is responsible for day-to-day management of our data privacy program and also reports directly to the Executive Vice President and General Counsel. Our cybersecurity and data privacy teams, which report directly to our CSO and CECO, respectively, are tasked with implementing our programs in support of cybersecurity and data privacy risk management. We also have management-level teams and committees, which include and/or collaborate with our CSO and CECO, that support, among other things, our processes to assess and manage cybersecurity risk. These teams and committees provide summary reports on their activities and initiatives to appropriate senior executives, including the Executive Vice President and General Counsel and the Audit Committee or the Board, as appropriate.

CenterPoint Energy’s CSO joined CenterPoint Energy in September 2025 and has over two decades of experience in cybersecurity and risk management across diverse industries, and most recently served in senior leadership roles, including Chief Information Security Officer, for a global engineering, procurement, consulting and construction company. Our Executive Vice President and General Counsel has significant risk management, governance and litigation experience, which we believe are important leadership skills to help incorporate risk management, legal, disclosure and governance perspectives into the design of our cybersecurity program and in evaluating and responding to potential cybersecurity incidents.

Item 2. Properties

The following discussion is based on the Registrants’ businesses as of December 31, 2025.

Character of Ownership

We lease or own our principal properties in fee, including our corporate office space and various real property. Most of our electric lines and natural gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Electric (CenterPoint Energy and Houston Electric)

Properties

All of Houston Electric's properties are located in Texas. Its properties consist primarily of high-voltage electric transmission lines and poles, distribution lines, substations, service centers, service wires, telecommunications networks and meters. Most of Houston Electric's transmission and distribution lines have been constructed over lands of others pursuant to easements or along public highways and streets under franchise agreements and as permitted by law. All real and tangible properties of Houston Electric, subject to certain exclusions, are currently subject to the lien of the M&DOT and the lien of the General Mortgage, which is junior to the lien of the M&DOT. No first mortgage bonds are outstanding under the M&DOT and Houston Electric is contractually obligated to not issue any additional first mortgage bonds under the M&DOT. Houston Electric is undertaking actions to release the lien of the M&DOT and terminate the M&DOT. For information related to debt outstanding under the General Mortgage, see Note 12 to the consolidated financial statements.

Indiana Electric's properties are primarily located in Indiana. They consist of transmission lines in Indiana and Kentucky, distribution lines, substations, service centers, coal-fired generating facilities, gas-fired turbine peaking units, a landfill gas electric generation facility and solar generation facilities. All real and tangible properties of Indiana Electric, subject to certain exclusions, are currently subject to the lien of the Amended and Restated Mortgage Indenture dated as of January 1, 2023, between SIGECO (Indiana Electric) and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as Trustee. For information related to debt outstanding under the Amended and Restated Mortgage Indenture, see Note 12 to the consolidated financial statements.

Electric Lines - Transmission and Distribution. As of December 31, 2025, Houston Electric and Indiana Electric owned and operated the following electric transmission and distribution lines:

Description	Houston Electric		Indiana Electric	
	Overhead Lines	Underground Lines	Indiana	Kentucky (1)
Transmission lines:				
		(in Circuit Miles)		
69 kV	101	2	565	—
138 kV	2,352	24	417	9
345 kV	1,446	—	48	16
Total	3,899	26	1,030	25
Distribution lines	29,718	29,841	7,174	—

(1) These assets interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Seabee, Kentucky.

Generating Capacity: As of December 31, 2025, Indiana Electric had 1,228 MW of installed generating capacity, as set forth in the following table:

Generation Source	Unit No.	Location	Date in Service	Capacity (MW)
Coal				
F.B. Culley (1)	2	Warrick County, Indiana	1966	90
F.B. Culley	3	Warrick County, Indiana	1973	270
Total Coal Capacity				360
Gas				
Brown (2)	3	Posey County, Indiana	1991	80
Brown	4	Posey County, Indiana	2002	80
Brown	5	Posey County, Indiana	2025	230
Brown	6	Posey County, Indiana	2025	230
Renewable Landfill Gas		Pike County, Indiana	2009	3
Total Gas Capacity				623
Solar				
Oak Hill		Evansville, Indiana	2018	2
Volkman		Evansville, Indiana	2018	2
Troy		Spencer County, Indiana	2021	50
Posey		Posey County, Indiana	2025	191
Total Solar Capacity				245
Total Generating Capacity (3)				1,228

(1) While Indiana Electric's 2025 IRP (similar to previous IRPs) preferred portfolios included the retirement of F.B. Culley Unit 2, a coal-fired generation unit, by the end of 2025, the U.S. Department of Energy issued an emergency 202(c) order in December 2025 directing Indiana Electric to continue operating the unit through March 23, 2026. For further information about F.B. Culley 2, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

(2) Brown Unit 3 is also equipped to burn oil.

(3) Excludes 1.5% participation in OVEC. See Item 1. Business for more details.

Natural Gas Combustion Turbines. In 2022, Indiana Electric received approval from the IURC for a CPCN seeking approval to construct two natural gas combustion turbines to replace portions of its existing coal-fired generation fleet. In the second quarter of 2025, 230 MW of the facility was placed in service, and due to a transformer manufacturing issue, the remaining 230 MW of the facility was placed in service in the third quarter of 2025. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Solar. On February 7, 2023, Indiana Electric filed a CPCN with the IURC to approve an amended BTA to purchase the 191 MW Posey Solar project. On September 6, 2023, the IURC issued an order approving the CPCN. On March 7, 2025, SIGECO completed the acquisition of Posey Solar. The Posey Solar project was placed in service in the second quarter of 2025. For further information about Indiana Electric's BTAs, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

TEEEF. As allowed by a law enacted by the Texas legislature after the February 2021 Winter Storm Event and amended in 2023, Houston Electric entered into leases for 15 large (27 MW to 32 MW) and five medium (5.7 MW) TEEEF. In June 2025, Houston Electric entered into the ERCOT Transaction, subject to PUCT approval, to release its large TEEEF units to ERCOT at CPS Energy facilities to serve the greater San Antonio region until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction, reduce its TEEEF fleet capacity and reduce its rates to reflect the removal of the large TEEEF units from its fleet. In November 2025, Houston Electric also proposed to release the five medium (5.7 MW) TEEEF units from its TEEEF fleet and remove the associated lease costs effective January 1, 2026. On February 13, 2026, Houston Electric requested continued abatement until February 27, 2026 due to continued settlement discussions. As of December 31, 2025, Houston Electric leased 519 MW of TEEEF on a long-term basis. For more information, see Note 7 and Note 19 to the consolidated financial statements.

Substations. A substation is a facility that transforms electricity from a higher voltage to a lower voltage or vice versa. Generally, this facility is the interface between the transmission system and the distribution grid. The following table presents certain information related to CenterPoint Energy's substations as of December 31, 2025:

	Number of Substations	Transformer Capacity (in Mva)
Houston Electric	246	74,665
Indiana Electric	109	7,027
Total CenterPoint Energy	355	81,692

Service Centers. Service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity. The following table presents certain information related to CenterPoint Energy's service centers as of December 31, 2025:

	Number of Service Centers	Acres of Land
Houston Electric	13	362
Indiana Electric	6	69
Total CenterPoint Energy	19	431

Natural Gas (CenterPoint Energy and CERC)

CenterPoint Energy's and CERC's natural gas distribution businesses use various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. CenterPoint Energy's and CERC's natural gas distribution businesses may also supplement contracted supplies and storage from time to time with stored LNG and propane-air plant production.

As of December 31, 2025, CenterPoint Energy's and CERC's natural gas distribution businesses owned and operated the following natural gas facilities:

	No. of Assets	Storage Capacity (Bcf)	Working Capacity (Bcf)	Maximum Daily Withdrawal Rate (MMcf)
CenterPoint Energy				
Underground Natural Gas Storage Facility	8	43	14	305
CERC				
Underground Natural Gas Storage Facility	5	32	9	205

	No. of Assets	Daily Production Rate (Dth)	On-site Storage Capacity	
			Millions of Gallons	Dth
CenterPoint Energy and CERC				
Propane Air-Gas Manufacturing Plant	15	247,000	14	1,228,000
LNG Plant Facility	1	72,000	12	1,010,000

The table below reflects CenterPoint Energy's and CERC's natural gas distribution businesses contracted upstream storage services as of December 31, 2025:

	Storage Capacity (Bcf)	Maximum Peak Daily Delivery (MMcf)
Upstream Storage Service	100	2,209

The table below reflects the approximate total linear miles of distribution and transmission mains owned by CenterPoint Energy's and CERC's natural gas distribution businesses as of December 31, 2025:

	CenterPoint Energy	CERC
All Locations	72,000	69,000
Indiana and Ohio (1)	23,000	20,000

(1) Linear miles of distribution and transmission mains attributable to CEOH were approximately 6,000 miles.

CenterPoint Energy's and CERC's natural gas distribution businesses owned mains varying in size from one-half inch to 24 inches in diameter. CenterPoint Energy's and CERC's natural gas distribution businesses in Indiana and Ohio own mains that are located in Indiana and Ohio except for, in the case of CenterPoint Energy, pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported to customers in Indiana. Generally, in each of the cities, towns and rural areas served by CenterPoint Energy's and CERC's natural gas distribution businesses, CenterPoint Energy and CERC own the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which CenterPoint Energy's and CERC's natural gas distribution businesses receive gas are owned, operated and maintained by others, and their distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on land owned by suppliers.

As of December 31, 2025, CenterPoint Energy and CERC, through CEIP, owned and operated over 208 miles of intrastate pipeline in Texas. On March 31, 2025, CenterPoint Energy, through its subsidiary CERC Corp., completed the sale of its Louisiana and Mississippi natural gas LDC businesses, which included the intrastate pipelines owned by CEIP in Louisiana. On October 20, 2025, CenterPoint Energy, through CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

Item 3. Legal Proceedings

For a discussion of material legal and regulatory proceedings, including environmental legal proceedings that involve a governmental authority as a party and that the Registrants reasonably believe would result in \$1,000,000 or more of monetary sanctions, exclusive of interest and costs, under federal, state and local laws that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment, affecting the Registrants, read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report and Note 14(c) to the consolidated financial statements, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp.

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

CenterPoint Energy

As of February 13, 2026, CenterPoint Energy's common stock was held by approximately 20,378 shareholders of record. CenterPoint Energy's common stock is listed on the NYSE and NYSE Texas and is traded under the symbol "CNP."

The amount of future cash dividends will be subject to determination based upon CenterPoint Energy's financial condition and results of operations, future business prospects, any applicable contractual restrictions and other factors that the Board considers relevant and will be declared at the discretion of the Board. For further information on CenterPoint Energy's dividends, see Note 11 to the consolidated financial statements.

Repurchases of Equity Securities

During the quarter ended December 31, 2025, none of CenterPoint Energy's equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended, were purchased by or on behalf of CenterPoint Energy or any "affiliated purchasers," as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended.

Houston Electric

As of February 13, 2026, all of Houston Electric's 1,000 outstanding common shares were held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy.

CERC

As of February 13, 2026, all of CERC Corp.'s 1,000 outstanding shares of common stock were held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy.

Item 6. *[Reserved]*

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following combined discussion and analysis should be read in combination with the consolidated financial statements included in Item 8 herein. The discussion of CenterPoint Energy's consolidated financial information includes the results of CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp., which, along with CenterPoint Energy, Inc., are collectively referred to as the Registrants. Where appropriate, information relating to a specific Registrant has been segregated and labeled as such. Unless the context indicates otherwise, specific references to Houston Electric and CERC also pertain to CenterPoint Energy. In this combined Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric and CERC, unless otherwise stated. No Registrant makes any representation as to the information relating to the other Registrants or the subsidiaries of CenterPoint Energy, Inc. other than itself or its subsidiaries.

OVERVIEW

Background

CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems. For a detailed description of CenterPoint Energy's operating subsidiaries, see Note 1 to the consolidated financial statements.

Houston Electric is an indirect, wholly-owned subsidiary of CenterPoint Energy, which provides electric transmission service to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston.

CERC Corp. is an indirect, wholly-owned subsidiary of CenterPoint Energy, which (i) directly owns and operates natural gas distribution systems in Minnesota and Texas, (ii) indirectly, through Indiana Gas and CEIH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP.

On October 20, 2025, CenterPoint Energy, through its subsidiary CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEIH. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

Reportable Segments

We discuss our operating results on a consolidated basis and individually for each of our reportable segments. We are first and foremost an energy delivery company and it is our intention to remain focused on these regulated segments. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, competition, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to whose jurisdiction we are subject, among other factors.

Below is a summary of CenterPoint Energy's reportable segments as of December 31, 2025. For a detailed description of each reportable segment, as well as the assets included in each reportable segment, see Part I, Item 1. Business and Item 2. Properties.

- The Electric reportable segment consisted of electric transmission and distribution services in the Texas Gulf Coast area in the ERCOT region and electric transmission and distribution services primarily to southwestern Indiana and includes power generation and wholesale power operations in the MISO region.
- The Natural Gas reportable segment consisted of (i) intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial and industrial customers in Indiana, Minnesota, Ohio and Texas; (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; (iii) residential appliance repair and maintenance services along with HVAC equipment sales to customers in Minnesota; and (iv) home repair protection plans to natural gas customers in Indiana, Ohio and Texas through a third party. The Louisiana and Mississippi natural gas LDC businesses were included in the Natural Gas reportable segment through March 31, 2025. See Note 4 for additional detail.
- The Corporate and Other reportable segment consisted of (i) energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group; (ii) corporate support operations that support all of CenterPoint Energy's business operations; and (iii) office buildings and other real estate used for business operations.

Houston Electric and CERC each consist of a single reportable segment.

EXECUTIVE SUMMARY

We expect our businesses to continue to be affected by the key factors and trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Factors Influencing Our Businesses and Industry Trends

We are an energy delivery company with electric transmission, distribution and generation operations and natural gas distribution operations that serve more than seven million metered customers across four states. The majority of our revenues are generated from the transmission and delivery of electricity and the sale of natural gas by our subsidiaries.

We continue to execute on our strategic goals for our businesses that were set in September 2025. Pursuant to this business strategy and in light of the nature of our businesses, significant capital investments are reflected in our new 10-year capital plan. In September 2025, we announced our new 10-year capital plan to invest \$65 billion from 2026 through 2035, inclusive of a \$2 billion increase in previously planned capital expenditures through 2030, and in February 2026, we announced an additional increase to reflect total expenditures of approximately \$65.5 billion. Our 10-year capital plan is intended to advance economic

growth, improve the experience of our customers through enhancing the safety, reliability and resiliency of our systems and deliver consistent value for stakeholders across the jurisdictions in which we operate. These investments are not only intended to meet our customers' current needs, but are also in anticipation of future organic growth from a diverse set of economic drivers. This organic growth is anticipated to result in rapid load growth in our service territories (as further discussed below). To fund these capital investments, we rely on internally-generated cash, borrowings under our credit facilities, proceeds from commercial paper, cash proceeds from strategic transactions (such as our Energy Systems Group divestiture in 2023, the sale of our Louisiana and Mississippi natural gas LDC businesses in 2025 and the announced sale of our Ohio natural gas LDC business, which is expected to close in the fourth quarter of 2026) and issuances of equity and debt securities in the capital markets, including the issuance of non-recourse system restoration bonds at Houston Electric to recover costs incurred primarily during the year ended December 31, 2024 due to the May 2024 Storm Events, as well as Hurricane Beryl and other significant storms.

We strive to maintain investment grade ratings for our debt securities to access the capital markets on terms we consider reasonable. A reduction in our ratings generally would result in an increase in our borrowing costs for new issuances of debt, as well as borrowing costs under our existing revolving credit facilities, and may prevent us from accessing the commercial paper markets. Disruptions in the financial markets along with high or rising interest rates can also affect the availability of external financing on terms we consider attractive. In those circumstances, we may not be able to obtain certain types of external financing or may be required to accept terms less favorable than we would otherwise accept which, among other things, would negatively impact our ability to finance our capital plan. For that reason, we seek to maintain adequate liquidity for our businesses through existing credit facilities and prudent refinancing of existing debt.

Approximately 85% of our rate base has been subject to a rate case since the beginning of 2023, which supports clarity and stability through 2029 with final orders improving enterprise weighted average returns on equity. Additionally, approximately 85% of CenterPoint Energy's projected consolidated investments are expected to be recovered through interim capital recovery trackers or rate cases based on a forward test year. For additional detail, see "—Liquidity and Capital Resources —Regulatory Matters" below.

To assess our financial performance, our management primarily monitors the recovery of costs and return on investments by evaluating net income and capital expenditures, among other metrics, from our regulated service territories within our reportable segments. Within these broader financial measures, we monitor margins, natural gas and fuel costs, interest expense, capital spend, working capital requirements and operation and maintenance expense, among other significant metrics. In addition to these financial measures, we also monitor a number of variables that management considers important to gauge the performance of our reportable segments, including the number of customers, throughput, commodity prices, heating and cooling degree days, safety factors, system reliability and customer satisfaction.

CenterPoint Energy and CERC have weather normalization or other rate mechanisms that largely mitigate the impact of weather on their natural gas distribution businesses in Indiana, Minnesota and Ohio, as applicable. CenterPoint Energy's and CERC's natural gas distribution businesses in Texas and CenterPoint Energy's electric operations in Texas and Indiana do not have such mechanisms. As a result, fluctuations from normal weather may have a positive or negative effect on CenterPoint Energy's and CERC's natural gas distribution business' results in Texas and on CenterPoint Energy's electric operations' results in its Texas and Indiana service territories.

Management anticipates significant growth in electric demand over the next decade, especially in our Houston Electric territory where we forecast a nearly 50% increase in peak electric load demand to over 30 GW by 2029 and the demand nearly doubling by the mid 2030s, as compared to 2024. It is expected that the significant forecasted growth in this service territory will be driven by a diverse set of economic drivers, including data centers, energy refining and exports, advanced manufacturing and logistics. Management additionally believes that there are increased electric demand opportunities in our Indiana Electric jurisdiction; accordingly, Indiana Electric's 2025 IRP included a large load scenario with a corresponding alternative preferred portfolio. Additionally, management expects residential meter growth for Houston Electric to remain in line with long-term trends at approximately 2% annually. As discussed above, a significant portion of the planned investments in our new 10-year capital plan are intended to support this growth. There is significant uncertainty with respect to the forecasted load growth and our ability to capitalize on the opportunities presented by these developments. For more information regarding such risks, see Part I, Item 1A. "Risk Factors — General and Other Risks — We are exposed to risks related to changes in demand and energy consumption..." Typical customer growth in the jurisdictions served by the Natural Gas reportable segment is approximately 1% annually. Management expects residential meter growth for CERC to remain in line with long-term trends at approximately 1% annually. Nevertheless, this expected growth may be partially offset by adverse economic conditions, coupled with concerns for protecting the environment and increased availability of alternate energy sources, which may cause consumers to use less energy or avoid expansions of their facilities, including natural gas facilities. Long-term national trends indicate residential customers have reduced their energy consumption, which could adversely affect

our results. To the extent population growth is affected by lower energy prices and there is financial pressure on some of our customers who operate within the energy industry, there may be an impact on the growth rate of our customer base and overall demand for our services.

Macroeconomic and geopolitical developments, including high rates of inflation, supply chain disruptions, labor market constraints, tariffs, high interest rates, general economic slowdown and escalating global conflicts can impact our business, financial condition, results of operations and cash flow, including adversely impacting our ability to execute on our 10-year capital plan. Inflation and high interest rates have contributed, and may continue to contribute, to increased prices for materials and services experienced by us and other companies in our industry. Further, the global supply chain has experienced and may continue to experience significant disruptions due to a multitude of factors, such as geopolitical and economic uncertainty, regulatory and policy instability, tariffs and other changes in U.S. and foreign trade policy, changes in laws (including tax laws), executive orders, labor shortages, resource availability, long lead times, manufacturer production limitations, delivery delays, inflation, severe weather events and disruptions to internal or international shipping, including as a result of armed conflicts. We have also faced, and may continue to face, a shortage of experienced and qualified personnel in certain positions, which has resulted in increased competition for skilled labor and wage inflation. Additionally, increased demand for materials necessary for our business has resulted, and may continue to result, in greater competition for and scarcity of such materials. In 2025 and 2026, the U.S. government threatened, announced and, in certain cases, rescinded, tariffs on several foreign jurisdictions and imports (including steel) into the United States, which led, and may continue to lead, to the imposition of retaliatory tariffs and other measures taken by foreign jurisdictions. There is significant uncertainty as to the scope and durability of existing and future tariff measures, as well as the ultimate effects of the tariffs on economic conditions. These macroeconomic and geopolitical developments have adversely impacted the utility industry, and like many of our peers, we have experienced disruptions to our supply chain, as well as increased prices and scarcity of resources and labor, and we may continue to experience this in the future. These developments have impacted our financial results for the year ended December 31, 2025. We have taken actions across multiple vectors to reduce the impact of such developments on our results of operations, but if such conditions continue, they could negatively impact our ability to procure materials, supplies (such as natural gas) or services necessary for our business and 10-year capital plan at a reasonable cost in a timely manner, result in project cancellations or scope changes, delays, cost overruns, and under-recovery of costs and challenges to our ability to remain in compliance with applicable laws, regulations and policies, which could adversely affect our business, financial condition, results of operations and cash flows. For more information regarding such risk, see Part I, Item 1A. “Risk Factors — Risk Factors Affecting Financial, Economic and Market Risks — Disruptions to the global supply chain...” and “— Changes in U.S. or foreign trade policies.”

The utility industry has experienced a period of rising costs and investments and an upward trend in spending, especially with respect to infrastructure investments. As noted above, we are making, and plan to continue to make, significant capital investments in our service territories under our 10-year capital plan to help operate and maintain safer, more reliable and growing electric and natural gas systems and support the electric demand growth that management is forecasting over the next decade. Rising costs and investments and the upward trend in spending are likely to continue in the foreseeable future and could result in more frequent rate cases and requests for, and the continuation of, cost recovery mechanisms. Increased rates and impacts on customer bills or the perceived potential for such impacts, particularly in the current economic environment, has caused and could continue to cause customer affordability concerns, resistance from customers and other stakeholders and increased political, regulatory, community and other scrutiny and pressures. For example, in consideration of customer affordability concerns, Indiana Electric cancelled nearly \$1 billion in renewable energy generation projects in 2025. These matters could impact our ability to execute our 10-year capital plan, result in adverse ratemaking and cost recovery determinations, increased financing needs and otherwise adversely affect our business, financial condition, results of operations and cash flows. For more information regarding such risk, see Part I, Item 1A. “Risk Factors.”

Significant Events

Updated 10-Year Capital Plan. On September 29, 2025, CenterPoint Energy announced a new 10-year capital plan to invest \$65 billion from 2026 through 2035, inclusive of a \$2 billion increase in previously planned capital expenditures through 2030. On February 19, 2026, CenterPoint Energy announced an additional increase of \$500 million to reflect total capital expenditures of approximately \$65.5 billion through 2035. The plan is expected to advance economic growth, enhance the experience of the Registrants’ customers and deliver consistent value for stakeholders across the Registrants’ jurisdictions.

Treasury Notice 2026-7. On February 18, 2026, Treasury Notice 2026-7 was issued. This notice clarifies the computation of AFSI by including an adjustment to deduct certain repair and maintenance costs that are capitalized in the applicable financial statement. While CenterPoint Energy is still evaluating this guidance, it expects a prospective reduction to its annual CAMT liability. Additionally, CenterPoint Energy expects to be able to amend prior year tax returns to claim a refund of CAMT paid.

TEEEF. In June 2025, Houston Electric entered into the ERCOT Transaction, subject to PUCT approval, to release its 15 large (27 MW to 32 MW) TEEEF units to ERCOT at CPS Energy facilities to serve the greater San Antonio region until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction, reduce its TEEEF fleet capacity and reduce its rates to reflect removal of the large TEEEF units from its fleet. Following the completion of service in the San Antonio area, Houston Electric anticipates that it would complete one or more future transactions involving its large TEEEF units. As the large TEEEF units would not be available to serve Houston Electric customers during such time, Houston Electric plans to continue to not charge customers for these units for any future periods. In November 2025, Houston Electric proposed to release its five medium (5.7 MW) TEEEF units and to remove the associated lease costs from its rates effective January 1, 2026. On February 13, 2026, Houston Electric requested continued abatement until February 27, 2026 due to continued settlement discussions. For additional information, see Note 7 to the consolidated financial statements.

Debt Transactions. In 2025, CenterPoint Energy issued or borrowed a combined \$3.7 billion of new debt, including: (i) SIGECO's issuance of \$515 million aggregate principal amount of its first mortgage bonds; (ii) Houston Electric's issuance of \$1.1 billion aggregate principal amount of its general mortgage bonds; (iii) Restoration Bond Company II's issuance of approximately \$401.5 million aggregate principal amount of its securitization bonds; (iv) CenterPoint Energy's issuance of \$1.0 billion aggregate principal amount of its convertible senior notes due 2028; and (v) CenterPoint Energy's issuance of \$700 million aggregate principal amount of its junior subordinated notes. During 2025, CenterPoint Energy repaid or redeemed a combined \$61 million of outstanding debt, including \$41 million of SIGECO's first mortgage bonds and \$20 million of Indiana Gas's senior notes. In addition, CenterPoint Energy repurchased a combined of approximately \$1.5 billion of outstanding debt in connection with settlement of its tender offers, including: (i) approximately \$963 million of its senior notes; (ii) approximately \$415 million of CERC's senior notes; and (iii) approximately \$234 million of Houston Electric's general mortgage bonds. For further information about debt transactions in 2025, see Note 12 to the consolidated financial statements. In January 2026, CERC Corp. entered into a delayed draw term loan agreement pursuant to which the banks party thereto have committed to provide term loans in an aggregate principal amount of up to \$800 million by March 30, 2026 in up to three separate borrowings, subject to the satisfaction or waiver of certain customary conditions. If not fully utilized, the term loan commitments expire on March 31, 2026. CERC Corp. borrowed \$500 million on January 20, 2026, and expects to borrow the remaining \$300 million during the first quarter of 2026. For further information, see Note 20 to the consolidated financial statements.

Assets Held for Sale. On October 20, 2025, CenterPoint Energy, through its subsidiary CERC Corp., entered into the Ohio Securities Purchase Agreement, pursuant to which CERC Corp. has agreed to sell all of the issued and outstanding equity interests in CEOH. The purchase price is \$2.62 billion, which is comprised of the following: (i) \$1.42 billion in cash payable to CERC Corp. upon closing of the transaction, subject to adjustments as set forth in the Ohio Securities Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing of the transaction; and (ii) a 364-day seller promissory note, in the original principal amount of \$1.2 billion, to be issued by NFGC at the closing of the transaction and payable to CERC Corp. as provided by the terms and conditions of the Seller Note Agreement. The transaction is not subject to a financing condition and is expected to close in the fourth quarter of 2026, subject to satisfaction of customary closing conditions. As of December 31, 2025, the assets included approximately 6,000 miles of transmission and distribution pipeline in Ohio serving approximately 337,000 metered customers. CEOH is reflected in CenterPoint Energy's Natural Gas reportable segment and CERC's single reportable segment, as applicable. For further information, see Note 4 to the consolidated financial statements.

CenterPoint Energy Board Leadership Structure Changes. On October 8, 2025, the Board unanimously appointed Jason P. Wells, Chief Executive Officer and President of CenterPoint Energy, to serve as Chair of the Board, effective immediately. Mr. Wells has served as a director on the Board since January 5, 2024. In addition, the Board approved the creation of a Lead Independent Director of the Board position and the independent directors of the Board unanimously appointed independent director Christopher H. Franklin to serve as the Lead Independent Director of the Board, effective immediately.

CenterPoint Energy Appointment of Chief Operating Officer. On July 21, 2025, CenterPoint Energy announced the appointment of Jesus Soto, Jr. to the position of Executive Vice President and Chief Operating Officer of CenterPoint Energy, effective August 11, 2025.

OBBBA and Executive Order 14315. On July 4, 2025, the OBBBA was signed into law. The OBBBA includes significant provisions, such as the permanent extension of certain expiring provisions of the TCJA and numerous changes to the energy tax credits initially introduced and expanded under the IRA. The legislation has multiple effective dates, with certain provisions effective in 2025 and others implemented through 2027. Additionally, on July 7, 2025, President Trump issued Executive Order 14315, which relates to the implementation of such changes to energy tax credits. The Registrants have assessed the potential effects of the OBBBA and Executive Order 14315 and concluded that neither is expected to have a material impact on their

future financial results because the Registrants have limited generation activities qualifying for tax credits under the IRA. The Registrants will consider the impacts of the OBCCA and Executive Order 141315, as well as related guidance, on any future generation projects, including any BTAs or PPAs, as applicable.

Equity Transactions. In April 2025, Centerpoint Energy entered into forward sales agreements pursuant to the Equity Distribution Agreement with certain of the ATM Forward Purchasers. In May 2025, CenterPoint Energy entered into separate forward sale agreements with certain financial institutions. For further information about forward sales in 2025, see Note 11 to the consolidated financial statements.

Regulatory Proceedings. In 2024, Houston Electric filed an Application for Determination of System Restoration Costs and a Financing Order with the PUCT for the May 2024 Storm Events, which were settled in 2025. In 2025, Houston Electric filed an Application for Determination of System Restoration Costs and a Financing Order with the PUCT for Hurricane Beryl and subsequent storm events, which were settled in 2025. For further information, see Note 7 to the consolidated financial statements. For information related to our pending and completed regulatory proceedings in 2025 and to date in 2026, see “—Liquidity and Capital Resources —Regulatory Matters” below.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. The magnitude of our future earnings and results of our operations will depend on or be affected by numerous factors that apply to all Registrants unless otherwise indicated including:

- The business strategies and strategic initiatives, restructurings, joint ventures and acquisitions or dispositions of assets or businesses involving us or our industry, including the ability to successfully complete such strategies, initiatives, transactions or plans on the timelines we expect or at all, such as the announced sale of our Ohio natural gas LDC business, which we cannot assure will have the anticipated benefits to us;
- industrial, commercial and residential growth in our service territories and changes in market demand and energy consumption, including in relation to the expansion of data centers (associated with, among other things, increasing demand for AI), energy refining and exports, advanced manufacturing and logistics, as well as the effects of energy efficiency measures, technological advances and demographic patterns, and our ability to appropriately estimate/forecast and effectively manage such demand and the business opportunities relating to such matters;
- our ability to fund and invest planned capital and the timely recovery of our investments, including the timing of and amounts sought for those related to our 10-year capital plan;
- our ability to execute and complete our planned capital projects and programs, including those within our 10-year capital plan, in a timely and cost-effective manner and within budget, obtain the anticipated benefits of such projects, and manage costs and impacts of such projects on customer affordability;
- our ability to successfully construct, operate, repair, maintain, replace and restart electric generating facilities, natural gas facilities, TEEEF and electric transmission facilities, as applicable, including in the event of an outage and in relation to complying with applicable environmental, reliability and safety standards;
- timely and appropriate rate actions that allow and authorize timely recovery of costs and a reasonable return on investment, including the timing of and amounts sought for recovery of Houston Electric’s applicable TEEEF leases and restoration costs relating to, among other things, Hurricane Beryl, and requested or favorable adjustments to rates and approval of other requested items as part of base rate proceedings or interim rate mechanisms;
- the timing and success of, and our ability to obtain approval for matters relating to, Houston Electric’s release of its large TEEEF units to the San Antonio area, proposed release of its medium TEEEF units, reduction of its TEEEF fleet capacity and reduction of rates to reflect the removal of the large and medium TEEEF units from Houston Electric’s TEEEF fleet, as well as Houston Electric’s ability to complete one or more other future transactions involving the large and medium TEEEF units on acceptable terms and conditions within the anticipated timeframe;
- economic conditions in regional and national markets, including economic uncertainty and volatility, potential for recession, changes to and increases in inflation and interest rates, and their effect on sales, prices and costs;
- severe weather events, natural disasters and other climate-related impacts, including the impact of severe weather events on operations, capital, legislation and/or regulations, such as seen in connection with the February 2021 Winter Storm Event, the May 2024 Storm Events and Hurricane Beryl;
- volatility in the markets for natural gas as a result of, among other factors, inflation, adverse weather conditions, supply and demand changes, availability of competitively priced alternative energy sources, political and geopolitical instability, commodity production levels and storage capacity, energy and environmental legislation and regulation and economic and financial market conditions;

- non-payment for our services due to financial distress of our customers and the ability of our customers, including REPs, to satisfy their obligations to CenterPoint Energy, Houston Electric and CERC, and the negative impact on such ability related to adverse economic conditions and severe weather events;
- public health threats, and their effect on our operations, business and financial condition, our industries and the communities we serve, U.S. and world financial markets and supply chains, potential regulatory actions and changes in customer and stakeholder behavior relating thereto;
- federal, state and local legislative, executive and regulatory actions or developments affecting various aspects of our businesses, including, among others, any actions resulting from Hurricane Beryl, energy deregulation or re-regulation, pipeline integrity and safety, actions relating to our facilities and changes in regulation, legislation and governmental action pertaining to the utility model, trade (including tariffs, bans, retaliatory trade measures taken against the United States or related governmental action), the implementation of budget and spending cuts to federal government agencies and programs, effects of government shutdowns, policies incentivizing or disincentivizing the development or utilization of alternative sources of generation (including distributed generation), health care, finance and actions regarding the rates charged by our regulated businesses;
- disruptions to the global supply chain, inflation, labor shortages and scarcity of certain materials, including as a result of changes in U.S. and foreign trade policy, geopolitical and economic uncertainty, regulatory and policy instability, severe weather and other catastrophic events, changes in laws, executive orders, legislation and other governmental action, increased competition for skilled labor and increases in demand for electricity, that could prevent CenterPoint Energy from securing the resources and labor needed to, among other things, fully execute on its strategy and 10-year capital plan, and otherwise impact the affordability of our rates for our customers;
- operations and maintenance costs, our ability to control such costs and cost-related impacts on the affordability of our rates for our customers;
- our ability to timely obtain and maintain necessary licenses, permits, easements and approvals from local, federal and other regulatory authorities on acceptable terms and resolve third-party challenges to such licenses, permits or approvals as applicable;
- direct or indirect effects on our facilities, resources, operations, reputation and financial condition resulting from terrorism, vandalism, cyberattacks or intrusions, data security breaches or other security incidents, threats or attempts to disrupt our businesses or the businesses of supply chain stakeholders (including by foreign actors), or other catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, tornadoes, derecho events, ice storms and other severe weather events, wildfires, pandemic health events, geopolitical conflict, civil unrest or other occurrences;
- the impact of negative opinions of us or our utility services that our customers, investors, legislators, regulators, creditors, rating agencies or other stakeholders may have or develop, which could result from a variety of factors, including actual or perceived failures in system reliability and safety, the speed of our response to service interruptions, rates and customer affordability, our ability to successfully execute our capital plan, media coverage and actions by third parties;
- damages to our network, facilities and systems, including as a result of wildfires, as well as to third-party property resulting in outages or shortages in our service territories, and losses in excess of insurance liability coverage;
- tax legislation and guidance and any changes in tax laws under the current or future administrations, including any further changes to or clarification of the IRA or the OBBBA, and any potential changes to tax rates, CAMT imposed, tax credits and/or interest deductibility, as well as uncertainties involving state commissions' and local municipalities' regulatory requirements and determinations regarding the treatment of EDIT and our rates;
- our ability to mitigate weather impacts through normalization or rate mechanisms, and the effectiveness of such mechanisms;
- actions by credit rating agencies, including any potential downgrades to credit ratings;
- local, state and federal legislative, executive and regulatory actions or developments relating to the environment, including, among others, those related to global climate risk, air emissions, GHG emissions, carbon emissions, wastewater discharges and the handling and disposal of CCR that could impact operations, cost recovery of generation plant costs and related assets, and CenterPoint Energy's energy transition goals;
- the impact of unplanned facility outages or other closures;
- the sufficiency of our insurance coverage, including availability, cost, coverage and terms and ability to recover claims;
- impacts from CenterPoint Energy's pension and postretirement benefit plans, such as the investment performance and increases to net periodic costs as a result of plan settlements and changes in assumptions, including discount rates;
- changes in interest rates and their impact on costs of borrowing and the valuation of CenterPoint Energy's pension benefit obligation;

- commercial bank and financial market conditions, including disruptions in the banking industry, our access to capital, the cost of such capital, the results of our financing and refinancing efforts, including availability of funds in the capital markets, and impacts on our vendors, customers and suppliers;
- inability of various counterparties to meet their obligations to us;
- the extent and effectiveness of our risk management activities;
- timely and appropriate regulatory actions, which include actions allowing requested securitization for any hurricanes or other severe weather events, such as Hurricane Beryl, or natural disasters or other amounts sought for recovery of costs, including stranded coal-fired generation asset costs;
- our ability to attract, effectively transition, motivate and retain an appropriately qualified workforce, identify and develop top talent to succeed management and maintain good labor relations;
- changes in technology, including with respect to efficient battery storage or the emergence or growth of new, developing or alternative sources of generation, and their adoption by consumers, and our ability to anticipate, adapt to and implement technological changes;
- advances in AI and our success in timely adopting, developing and deploying AI;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- the recording of impairment charges;
- political and economic developments and actions, including energy and environmental policies under the current administration;
- CenterPoint Energy's ability to execute on its strategy, initiatives, targets and goals, including energy transition goals and operations and maintenance expenditure goals;
- the outcome of litigation, including litigation related to the February 2021 Winter Storm Event and Hurricane Beryl;
- the effect of changes in and application of accounting standards and pronouncements; and
- other factors discussed in "Risk Factors" in Part I, Item 1A of this report and in other reports that the Registrants file from time to time with the SEC.

CENTERPOINT ENERGY CONSOLIDATED RESULTS OF OPERATIONS

CenterPoint Energy's results of operations are affected by seasonal fluctuations in the demand for electricity and natural gas. CenterPoint Energy's results of operations are also affected by, among other things, the actions of various governmental authorities having jurisdiction over rates its subsidiaries charge, debt service costs, income tax expense, its subsidiaries ability to collect receivables from REPs and customers and its ability to recover its regulatory assets. For information regarding factors that may affect the future results of our consolidated operations, see "Risk Factors" in Part I, Item 1A of this report.

Net income (loss) available to common shareholders was as follows for the periods presented:

	Year Ended December 31,			Favorable (Unfavorable)	
	2025	2024	2023	2025 to 2024	2024 to 2023
	(in millions)				
Electric	\$ 705	\$ 671	\$ 654	\$ 34	\$ 17
Natural Gas (1)	570	566	533	4	33
Corporate & Other (2)	(223)	(218)	(320)	(5)	102
Total CenterPoint Energy	<u>\$ 1,052</u>	<u>\$ 1,019</u>	<u>\$ 867</u>	<u>\$ 33</u>	<u>\$ 152</u>

(1) Includes results of operations from Louisiana and Mississippi natural gas LDC businesses through the date of the sale on March 31, 2025.

(2) Includes energy performance contracting and sustainable infrastructure services through Energy Systems Group through the date of sale on June 30, 2023, unallocated corporate costs, interest income and interest expense, intercompany eliminations and the reduction of income allocated to preferred shareholders through September 1, 2023, the date of the redemption of all of the outstanding shares of the Series A Preferred Stock.

2025 Compared to 2024

Net income available to common shareholders increased \$33 million primarily due to the following items:

- an increase in income available to common shareholders of \$34 million for the Electric reportable segment, as further discussed below;
- an increase in income available to common shareholders of \$4 million for the Natural Gas reportable segment, as further discussed below; and
- a decrease in income available to common shareholders of \$5 million for the Corporate and Other reportable segment, primarily due to increased borrowing costs of approximately \$37 million, offset by a \$21 million gain on early extinguishment of debt using proceeds from the divestiture of the Louisiana and Mississippi natural gas LDCs, and a \$20 million gain on early extinguishment of debt associated with the October 2025 tender offer, which is further discussed in Note 12 to the consolidated financial statements. The remaining variance is primarily driven by an increase in other corporate expenses, including expenses associated with proposed divestitures.

2024 Compared to 2023

Net income available to common shareholders increased \$152 million primarily due to the following items:

- an increase in income available to common shareholders of \$17 million for the Electric reportable segment, as further discussed below;
- an increase in income available to common shareholders of \$33 million for the Natural Gas reportable segment, as further discussed below; and
- an increase in income available to common shareholders of \$102 million for the Corporate and Other reportable segment, primarily due to \$50 million of income allocated to holders of Series A Preferred Stock in 2023 prior to the redemption of all outstanding shares of Series A Preferred Stock in September 2023 as discussed in Note 11 to the consolidated financial statements, a loss on sale of \$13 million and current tax expense of \$32 million related to the divestiture of Energy Systems Group recorded in 2023 further discussed in Note 4 to the consolidated financial statements, \$19 million due to remeasurement of deferred income tax balances recorded during 2023, as well as \$8 million due to lower state income taxes. The remaining variance is due largely to an increase in borrowing costs.

Income Tax Expense. For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

CENTERPOINT ENERGY'S RESULTS OF OPERATIONS BY REPORTABLE SEGMENT

CenterPoint Energy's CODM views net income as the measure of profit or loss for the reportable segments. Segment results include inter-segment interest income and expense, which may result in inter-segment profit and loss.

The following discussion of CenterPoint Energy's results of operations is separated into two reportable segments, Electric and Natural Gas.

Electric (CenterPoint Energy)

The following table provides summary data of CenterPoint Energy's Electric reportable segment for the periods presented:

	Year Ended December 31,			Favorable (Unfavorable)	
	2025	2024	2023	2025 to 2024	2024 to 2023
	(in millions, except throughput, weather and customer data)				
Revenues	\$ 4,866	\$ 4,590	\$ 4,290	\$ 276	\$ 300
Expenses:					
Utility natural gas, fuel and purchased power	270	198	176	(72)	(22)
Operation and maintenance	2,084	2,072	1,880	(12)	(192)
Depreciation and amortization	946	877	872	(69)	(5)
Taxes other than income taxes	321	304	272	(17)	(32)
Total expenses	3,621	3,451	3,200	(170)	(251)
Operating Income	1,245	1,139	1,090	106	49
Other Income (Expense):					
Interest expense and other finance charges	(445)	(372)	(303)	(73)	(69)
Other income, net	77	61	56	16	5
Income Before Income Taxes	877	828	843	49	(15)
Income tax expense	172	157	189	(15)	32
Net Income	\$ 705	\$ 671	\$ 654	\$ 34	\$ 17
Throughput (in GWh):					
Residential	35,547	34,190	35,166	4 %	(3)%
Total	116,076	110,831	108,766	5 %	2 %
Weather (percentage of normal weather for service area):					
Cooling degree days	112 %	115 %	114 %	(3)%	1 %
Heating degree days	98 %	76 %	90 %	22 %	(14)%
Number of metered customers at end of period:					
Residential	2,679,575	2,640,150	2,588,510	1 %	2 %
Total	3,013,715	2,971,730	2,916,028	1 %	2 %

The following table provides variance explanations by major income statement caption for the Electric reportable segment:

	Favorable (Unfavorable)	
	2025 to 2024	2024 to 2023
	(in millions)	
Revenues		
Customer rates and impact of the change in rate design	\$ 109	\$ 143
Transmission Revenues, including TCOS and TCRF, inclusive of costs billed by transmission providers, partially offset in operation and maintenance below	88	217
Customer growth	26	26
Energy efficiency, partially offset in operation and maintenance below	29	5
Equity return, related to the annual true-up of transition charges for amounts over or under collected in prior periods	(18)	(20)
Pass-through revenues, offset in operation and maintenance below	3	(5)
Miscellaneous revenues, including service connections and off-system sales	(11)	1
Lost revenues as a result of outages associated with Hurricane Beryl in 2024	10	(10)
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items below	(62)	(70)
Weather, efficiency improvements and other usage impacts	40	(9)
Cost of fuel and purchased power, offset in utility natural gas, fuel and purchased power below	62	22
Total	\$ 276	\$ 300
Utility natural gas, fuel and purchased power		
Cost of purchased power, offset in revenues above	\$ (53)	\$ (87)
Cost of fuel, including coal, natural gas, and fuel oil, offset in revenues above	(19)	65
Total	\$ (72)	\$ (22)
Operation and maintenance		
Transmission costs billed by transmission providers, offset in revenues above	\$ (40)	\$ (124)
Incremental storm expenses, including storm hardening expenses incurred in connection with accelerated operational activities after Hurricane Beryl in 2024	112	(112)
Contract services	(34)	16
Energy efficiency, and other pass-through, offset in revenues above	(3)	(1)
Corporate support services	(28)	—
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items	3	—
Labor and benefits	(9)	4
All other operation and maintenance expense, including materials and supplies and insurance	(13)	25
Total	\$ (12)	\$ (192)
Depreciation and amortization		
Ongoing additions to plant-in-service	\$ (74)	\$ (79)
Lease expense associated with TEEEF units no longer eligible for regulatory deferral	(59)	—
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items	64	74
Total	\$ (69)	\$ (5)
Taxes other than income taxes		
Incremental capital projects placed in service, and the impact of updated property tax rates	\$ (17)	\$ (26)
Franchise fees and other taxes	—	(6)
Total	\$ (17)	\$ (32)
Interest expense and other finance charges		
Changes in outstanding debt	\$ (90)	\$ (63)
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items above	(2)	(4)
Other, primarily AFUDC and impacts of regulatory deferrals	19	(2)
Total	\$ (73)	\$ (69)
Other income (expense), net		
Other income, including AFUDC - equity	\$ 19	\$ 5
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items above	(3)	—
Total	\$ 16	\$ 5

Income Tax Expense. For a discussion of effective tax rate per period by Registrant, see Note 13 to the consolidated financial statements.

Natural Gas (CenterPoint Energy)

The following table provides summary data of CenterPoint Energy's Natural Gas reportable segment for the periods presented:

	Year Ended December 31,			Favorable (Unfavorable)	
	2025	2024	2023	2025 to 2024	2024 to 2023
	(in millions, except throughput, weather and customer data)				
Revenues	\$ 4,486	\$ 4,050	\$ 4,279	\$ 436	\$ (229)
Expenses:					
Utility natural gas and fuel	1,846	1,520	1,888	(326)	368
Non-utility cost of revenues, including natural gas	4	3	3	(1)	—
Operation and maintenance	931	881	949	(50)	68
Depreciation and amortization	563	542	513	(21)	(29)
Taxes other than income taxes	245	237	245	(8)	8
Total expenses	3,589	3,183	3,598	(406)	415
Operating Income	897	867	681	30	186
Other Income (Expense):					
Loss on sale	(49)	—	—	(49)	—
Interest expense and other finance charges	(208)	(207)	(188)	(1)	(19)
Other income (expense), net	27	14	15	13	(1)
Income Before Income Taxes	667	674	508	(7)	166
Income tax expense (benefit)	97	108	(25)	11	(133)
Net Income	\$ 570	\$ 566	\$ 533	\$ 4	\$ 33
Throughput (in Bcf):					
Residential	220	189	199	16 %	(5)%
Commercial and industrial	423	426	418	(1)%	2 %
Total Throughput	643	615	617	5 %	— %
Weather (percentage of 10-year average for service area):					
Heating degree days	96 %	78 %	86 %	18 %	(8)%
Number of metered customers at end of period:					
Residential	3,739,919	4,063,928	4,010,113	(8)%	1 %
Commercial and industrial	289,166	304,606	303,841	(5)%	— %
Total (1)	4,029,085	4,368,534	4,313,954	(8)%	1 %

(1) Decrease in number of metered customers from 2024 to 2025 is primarily attributable to customer accounts associated with the divestiture of the Louisiana and Mississippi natural gas LDCs in March 2025. See Note 4 for additional detail.

The following table provides variance explanations by major income statement caption for the Natural Gas reportable segment:

	Favorable (Unfavorable)	
	2025 to 2024	2024 to 2023
	(in millions)	
Revenues		
Cost of natural gas, offset in utility natural gas and fuel below	\$ 384	\$ (368)
Gross receipts tax, offset in taxes other than income taxes below	14	1
Weather and usage	12	(11)
Non-volumetric and miscellaneous revenue	10	(5)
Energy efficiency and other pass-through, offset in operation and maintenance below	40	(20)
Non-utility revenues	2	15
Customer growth	14	14
Customer rates and impact of the change in rate design	142	145
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	(182)	—
Total	\$ 436	\$ (229)
Utility natural gas and fuel		
Cost of natural gas, offset in revenues above	\$ (384)	\$ 368
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	58	—
Total	\$ (326)	\$ 368
Non-utility costs of revenues, including natural gas		
Non-utility cost of revenues, including natural gas	\$ (1)	\$ —
Total	\$ (1)	\$ —
Operation and maintenance		
All other operations and maintenance expenses, including bad debt expense	\$ (15)	\$ 23
Energy efficiency and other pass-through, offset in revenues above	(40)	20
Contract services	(10)	(6)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	53	—
Labor and benefits	(25)	8
Corporate support services	(13)	23
Total	\$ (50)	\$ 68
Depreciation and amortization		
Ongoing additions to plant-in-service	\$ (60)	\$ (29)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	39	—
Total	\$ (21)	\$ (29)
Taxes other than income taxes		
Gross receipts tax, offset in revenues above	\$ (14)	\$ (1)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	15	—
Incremental capital projects placed in service, and the impact of updated property tax rates	(9)	9
Total	\$ (8)	\$ 8
Loss on Sale		
Loss on sale of Louisiana and Mississippi natural gas LDC businesses	\$ (49)	\$ —
Total	\$ (49)	\$ —
Interest expense and other finance charges		
Changes in outstanding debt	\$ (6)	\$ (12)
Other, primarily AFUDC and impacts of regulatory deferrals	(5)	(7)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	10	—
Total	\$ (1)	\$ (19)
Other income (expense), net		
Changes to non-service benefit cost	\$ 4	\$ 3
Other income, including interest income from affiliated companies and AFUDC - Equity	10	(4)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	(1)	—
Total	\$ 13	\$ (1)

Income Tax Expense (Benefit). For a discussion of effective tax rate per period by Registrant, see Note 13 to the consolidated financial statements.

HOUSTON ELECTRIC CONSOLIDATED RESULTS OF OPERATIONS

Houston Electric's CODM views net income as the measure of profit or loss for its reportable segment. Houston Electric consists of a single reportable segment. Houston Electric's results of operations are affected by seasonal fluctuations in the demand for electricity. Houston Electric's results of operations are also affected by, among other things, the actions of various governmental authorities having jurisdiction over rates Houston Electric charges, debt service costs, income tax expense, Houston Electric's ability to collect receivables from REPs and Houston Electric's ability to recover its regulatory assets. For information regarding factors that may affect the future results of Houston Electric's consolidated operations, see "Risk Factors" in Item 1A of Part I of this report.

The following table provides summary data of Houston Electric's single reportable segment for the periods presented:

	Year Ended December 31,			Favorable (Unfavorable)	
	2025	2024	2023	2025 to 2024	2024 to 2023
(in millions, except throughput, weather and customer data)					
Revenues:					
TDU	\$ 4,067	\$ 3,862	\$ 3,514	\$ 205	\$ 348
Bond Companies	17	77	163	(60)	(86)
Total revenues	4,084	3,939	3,677	145	262
Expenses:					
Operation and maintenance, excluding Bond Companies	1,913	1,923	1,669	10	(254)
Depreciation and amortization, excluding Bond Companies	795	688	593	(107)	(95)
Taxes other than income taxes	312	295	262	(17)	(33)
Bond Companies	12	78	159	66	81
Total expenses	3,032	2,984	2,683	(48)	(301)
Operating Income	1,052	955	994	97	(39)
Other Income (Expense):					
Interest expense and other finance charges	(369)	(311)	(259)	(58)	(52)
Interest expense on Securitization Bonds	(6)	(3)	(8)	(3)	5
Other income, net	48	43	34	5	9
Income Before Income Taxes	725	684	761	41	(77)
Income tax expense	147	138	168	(9)	30
Net Income	\$ 578	\$ 546	\$ 593	\$ 32	\$ (47)
Throughput (in GWh):					
Residential	34,101	32,769	33,830	4 %	(3)%
Total	111,083	106,014	103,862	5 %	2 %
Weather (percentage of 10-year average for service area):					
Cooling degree days	114 %	115 %	114 %	(1)%	1 %
Heating degree days	94 %	92 %	92 %	2 %	— %
Number of metered customers at end of period:					
Residential	2,544,880	2,506,284	2,455,309	2 %	2 %
Total	2,859,313	2,818,343	2,763,535	1 %	2 %

The following table provides variance explanations by major income statement caption for Houston Electric:

	Favorable (Unfavorable)	
	2025 to 2024	2024 to 2023
	(in millions)	
Revenues		
Customer rates and impact of the change in rate design	\$ 34	\$ 153
Transmission Revenues, including TCOS and TCRF, inclusive of costs billed by transmission providers, partially offset in operation and maintenance below	88	217
Customer growth	22	25
Energy efficiency, partially offset in operation and maintenance below	29	5
Miscellaneous revenues	13	1
Lost revenues as a result of outages associated with Hurricane Beryl in 2024	10	(10)
Equity return, related to the annual true-up of transition charges for amounts over or under collected in prior periods	(18)	(19)
Weather, efficiency improvements and other usage impacts	27	(24)
Bond Companies, offset in other line items below	(60)	(86)
Total	\$ 145	\$ 262
Operation and maintenance, excluding Bond Companies		
Transmission costs billed by transmission providers, offset in revenues above	\$ (40)	\$ (124)
Incremental storm expenses, including storm hardening expenses incurred in connection with accelerated operational activities after Hurricane Beryl in 2024	112	(112)
Contract services	(29)	7
Energy efficiency, offset in revenues above	(3)	(6)
Corporate support services	(23)	(2)
Labor and benefits	(8)	1
All other operation and maintenance expense, including materials and supplies and insurance	1	(18)
Total	\$ 10	\$ (254)
Depreciation and amortization, excluding Bond Companies		
Ongoing additions to plant-in-service	\$ (47)	\$ (95)
Lease expense associated with TEEEF units no longer eligible for regulatory deferral	(60)	—
Total	\$ (107)	\$ (95)
Taxes other than income taxes		
Incremental capital projects placed in service, and the impact of changes to tax rates	\$ (17)	\$ (26)
Franchise fees and other taxes	—	(7)
Total	\$ (17)	\$ (33)
Bond Companies		
Operations and maintenance and depreciation expense, offset in revenues above	\$ 66	\$ 81
Total	\$ 66	\$ 81
Interest expense and other finance charges		
Changes in outstanding debt	\$ (75)	\$ (55)
Other, primarily AFUDC and impacts of regulatory deferrals	17	3
Total	\$ (58)	\$ (52)
Interest expense on Securitization Bonds		
Change in outstanding principal balance, offset in revenues above	\$ (3)	\$ 5
Total	\$ (3)	\$ 5
Other income, net		
Other income, including AFUDC - equity	\$ 7	\$ 9
Bond Companies interest income, offset in other line items	(2)	—
Total	\$ 5	\$ 9

Income Tax Expense. For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

CERC CONSOLIDATED RESULTS OF OPERATIONS

CERC's CODM views net income as the measure of profit or loss for its reportable segment. CERC consists of a single reportable segment. CERC's results of operations are affected by seasonal fluctuations in the demand for natural gas. CERC's results of operations are also affected by, among other things, the actions of various federal, state and local governmental authorities having jurisdiction over rates CERC charges, debt service costs and income tax expense, CERC's ability to collect receivables from customers and CERC's ability to recover its regulatory assets. For information regarding factors that may affect the future results of CERC's consolidated operations, see "Risk Factors" in Item 1A of Part I of this report.

The following table provides summary data of CERC's single reportable segment for the periods presented:

	Year Ended December 31,			Favorable (Unfavorable)	
	2025	2024	2023	2025 to 2024	2024 to 2023
	(in millions, except throughput, weather and customer data)				
Revenues	\$ 4,344	\$ 3,925	\$ 4,149	\$ 419	\$ (224)
Expenses:					
Utility natural gas	1,803	1,489	1,856	(314)	367
Non-utility cost of revenues, including natural gas	4	3	3	(1)	—
Operation and maintenance	895	848	904	(47)	56
Depreciation and amortization	541	522	493	(19)	(29)
Taxes other than income taxes	242	234	243	(8)	9
Total expenses	3,485	3,096	3,499	(389)	403
Operating Income	859	829	650	30	179
Other Income (Expense):					
Gain on sale	46	—	—	46	—
Interest expense and other finance charges	(194)	(197)	(178)	3	(19)
Other income (expense), net	25	12	14	13	(2)
Income Before Income Taxes	736	644	486	92	158
Income tax expense (benefit)	97	104	(26)	7	(130)
Net Income	\$ 639	\$ 540	\$ 512	\$ 99	\$ 28
Throughput (in BCF):					
Residential	214	184	194	16 %	(5)%
Commercial and Industrial	379	390	386	(3)%	1 %
Total Throughput	593	574	580	3 %	(1)%
Weather (percentage of 10-year average for service area):					
Heating degree days	96 %	78 %	86 %	18 %	(8)%
Number of metered customers at end of period:					
Residential	3,634,422	3,958,584	3,905,388	(8)%	1 %
Commercial and Industrial	278,500	293,959	293,235	(5)%	— %
Total (1)	3,912,922	4,252,543	4,198,623	(8)%	1 %

(1) Decrease in number of metered customers is primarily attributable to customer accounts associated with the divestiture of the Louisiana and Mississippi natural gas LDCs in March 2025. See Note 4 for additional detail.

The following table provides variance explanations by major income statement caption for CERC:

	Favorable (Unfavorable)	
	2025 to 2024	2024 to 2023
(in millions)		
Revenues		
Cost of natural gas, offset in utility natural gas, fuel and purchased power below	\$ 372	\$ (367)
Gross receipts tax, offset in taxes other than income taxes below	14	1
Weather and usage	12	(9)
Energy efficiency and other pass-through, offset in operation and maintenance below	39	(10)
Non-volumetric and miscellaneous revenue	11	(6)
Non-utility revenues	2	15
Customer growth	14	13
Customer rates	137	139
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	(182)	—
Total	\$ 419	\$ (224)
Utility natural gas		
Cost of natural gas, offset in revenues above	\$ (372)	\$ 367
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	58	—
Total	\$ (314)	\$ 367
Operation and maintenance		
All other operations and maintenance expenses, including bad debt expense	\$ (12)	\$ 21
Energy efficiency and other pass-through, offset in revenues above	(39)	10
Contract services	(12)	(6)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	53	—
Labor and benefits	(25)	8
Corporate support services	(12)	23
Total	\$ (47)	\$ 56
Depreciation and amortization		
Ongoing additions to plant-in-service	\$ (58)	\$ (29)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	39	—
Total	\$ (19)	\$ (29)
Taxes other than income taxes		
Gross receipts tax, offset in revenues above	\$ (14)	\$ (1)
Incremental capital projects placed in service, and the impact of updated property tax rates	(9)	10
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	15	—
Total	\$ (8)	\$ 9
Gain on sale		
Gain on sale of Louisiana and Mississippi natural gas LDC businesses	\$ 46	\$ —
Total	\$ 46	\$ —
Interest expense and other finance charges		
Changes in outstanding debt	\$ (3)	\$ (11)
Other, primarily AFUDC and impacts of regulatory deferrals	(4)	(8)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	10	—
Total	\$ 3	\$ (19)
Other income (expense), net		
Changes to non-service benefit cost	\$ 4	\$ 3
Other income, including interest income from affiliated companies and AFUDC - Equity	10	(5)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs on March 31, 2025	(1)	—
Total	\$ 13	\$ (2)

Income Tax Expense (Benefit). For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following table summarizes the Registrants' cash flows by category for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Cash provided by (used in):									
Operating activities	\$ 2,486	\$ 1,177	\$ 1,262	\$ 2,139	\$ 960	\$ 1,068	\$ 3,877	\$ 1,401	\$ 2,312
Investing activities	(4,016)	(2,349)	(361)	(4,489)	(2,767)	(1,419)	(4,233)	(2,503)	(1,643)
Financing activities	1,549	1,187	(903)	2,271	1,732	352	374	1,103	(668)

Operating Activities. The following items contributed to increased (decreased) net cash provided by operating activities:

	2025 compared to 2024			2024 compared to 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Changes in net income after adjusting for non-cash items	\$ 76	\$ 97	\$ 25	\$ 315	\$ (132)	\$ 153
Changes in working capital (1)	(231)	(275)	48	(1,372)	191	(1,266)
Other non-current assets	511	370	274	(580)	(500)	(135)
Other non-current liabilities	189	52	(142)	(57)	(15)	49
Higher pension contribution	(100)	—	—	2	—	—
Other	(98)	(27)	(11)	(46)	15	(45)
	<u>\$ 347</u>	<u>\$ 217</u>	<u>\$ 194</u>	<u>\$ (1,738)</u>	<u>\$ (441)</u>	<u>\$ (1,244)</u>

(1) This change is primarily related to the receipt of proceeds at CenterPoint Energy and CERC from the issuance of customer rate relief bonds Texas by the Natural Gas Securitization Finance Corporation in 2023. For further details, see Note 7 to the consolidated financial statements.

Investing Activities. The following items contributed to (increased) decreased net cash used in investing activities:

	2025 compared to 2024			2024 compared to 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Payment for asset acquisition	\$ (357)	\$ —	\$ —	\$ —	\$ —	\$ —
Net change in capital expenditures	(357)	(189)	(88)	(112)	(363)	180
Net change in notes receivable from affiliated companies	—	498	(1)	—	108	2
Proceeds from divestitures	1,219	—	1,219	(144)	—	—
Other	(32)	109	(72)	—	(9)	42
	<u>\$ 473</u>	<u>\$ 418</u>	<u>\$ 1,058</u>	<u>\$ (256)</u>	<u>\$ (264)</u>	<u>\$ 224</u>

Financing Activities. The following items contributed to (increased) decreased net cash provided by (used in) financing activities:

	2025 compared to 2024			2024 compared to 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Net changes in commercial paper outstanding	\$ 537	\$ —	\$ (155)	\$ 516	\$ —	\$ 436
Net changes in proceeds from issuance of Common Stock	(494)	—	—	494	—	—
Net changes in long-term debt and term loans outstanding, excluding commercial paper	(770)	63	(819)	51	(6)	725
Net changes in debt and equity issuance costs	(11)	(10)	3	20	5	11
Net changes in short-term borrowings	1	—	1	6	—	6
Redemption of Series A Preferred Stock	—	—	—	800	—	—
Increased payment of Common Stock dividends	(52)	—	—	(37)	—	—
Decreased payment of preferred stock dividends	—	—	—	50	—	—
Net change in notes payable from affiliated companies	—	54	291	—	642	—
Change in dividend to parent	—	41	(288)	—	28	54
Change in contribution from parent	—	(750)	(290)	—	(41)	(210)
Other	67	57	2	(3)	1	(2)
	<u>\$ (722)</u>	<u>\$ (545)</u>	<u>\$ (1,255)</u>	<u>\$ 1,897</u>	<u>\$ 629</u>	<u>\$ 1,020</u>

Future Sources and Uses of Cash

Material Current and Long-term Cash Requirements. The liquidity and capital requirements of the Registrants are affected primarily by results of operations, capital expenditures, storm restoration costs, debt service requirements, tax payments, working capital needs and various regulatory actions. Future capital expenditures are expected to primarily relate to investments in infrastructure. These capital expenditures are anticipated to enhance the safety, reliability and resiliency of our systems and deliver consistent value for stakeholders across the Registrants' jurisdictions. In addition to dividend payments on CenterPoint Energy's Common Stock and interest payments on debt, the Registrants' principal anticipated cash requirements for 2026 include the following:

	CenterPoint Energy	Houston Electric	CERC
	(in millions)		
Estimated capital expenditures	\$ 6,695	\$ 4,031	\$ 2,198
Scheduled principal payments on Securitization Bonds	40	27	—
Scheduled principal payments on debt instruments, excluding Securitization Bonds	2,377	800	60
Expected contributions to pension plans and other postretirement plans	86	—	5

The Registrants expect that anticipated cash needs for 2026 will be met with available cash flows from operations, proceeds from the sale of our Ohio natural gas LDC business, as well as cash flows from financing (such as issuances of debt securities and equity securities upon physical settlement of outstanding forward sale agreements and borrowings under credit facilities, commercial paper issuances or other sources). The issuances of securities in the capital markets and borrowings under additional credit facilities and term loans may not, however, be available on acceptable terms. The Registrants may, from time to time, redeem, repurchase or otherwise acquire their outstanding debt securities through open market purchases, tender offers or pursuant to the terms of such securities.

The following table sets forth the Registrants' estimates of the Registrants' capital expenditures currently planned for projects for the periods presented. See Note 16 to the consolidated financial statements for CenterPoint Energy's actual capital expenditures by reportable segment for 2025.

	2026	2027	2028	2029	2030
CenterPoint Energy			(in millions)		
Electric	\$ 4,388	\$ 4,736	\$ 4,936	\$ 3,777	\$ 4,358
Natural Gas	2,288	2,163	2,122	1,924	2,024
Corporate and Other	19	20	20	20	20
Total	\$ 6,695	\$ 6,919	\$ 7,078	\$ 5,721	\$ 6,402
Houston Electric (1)	\$ 4,031	\$ 4,326	\$ 4,474	\$ 3,440	\$ 4,076
CERC (1)	\$ 2,198	\$ 2,047	\$ 1,994	\$ 1,826	\$ 1,899

(1) Houston Electric and CERC each consist of a single reportable segment.

The following table summarizes the Registrants' material current and long-term cash requirements as of December 31, 2025:

	2026	2027	2028	2029	2030	Thereafter	Total
CenterPoint Energy			(in millions)				
Short-term borrowings	\$ 500	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 500
Securitization Bonds (1)	40	37	39	41	43	514	714
Other long-term debt (1) (2)	1,877	326	3,941	870	1,469	13,470	21,953
Interest payments — Securitization Bonds (3)	38	32	30	28	26	134	288
Interest payments — other long-term debt (3)	1,024	956	914	749	3,170	8,223	15,036
Commodity and other commitments (4)	978	946	781	630	681	2,919	6,935
Total cash requirements	\$ 4,457	\$ 2,297	\$ 5,705	\$ 2,318	\$ 5,389	\$ 25,260	\$ 45,426
Houston Electric							
Short-term borrowings	\$ 500	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 500
Securitization Bonds (1)	27	23	24	25	26	277	402
Other long-term debt (1)	300	300	500	—	500	7,679	9,279
Interest payments — Securitization Bonds (3)	22	17	16	14	13	62	144
Interest payments — other long-term debt (3)	401	383	379	353	2,659	3,466	7,641
Total cash requirements	\$ 1,250	\$ 723	\$ 919	\$ 392	\$ 3,198	\$ 11,484	\$ 17,966
CERC							
Long-term debt (1)	\$ 60	\$ 26	\$ 1,779	\$ 30	\$ 500	\$ 2,345	\$ 4,740
Interest payments — long-term debt (3)	227	224	191	136	133	799	1,710
Commodity and other commitments (4)	684	587	542	522	480	1,322	4,137
Total cash requirements	\$ 971	\$ 837	\$ 2,512	\$ 688	\$ 1,113	\$ 4,466	\$ 10,587

- Balances reflect aggregate principal amounts outstanding and do not include unamortized discounts, premiums or issuance costs. See Note 12 to the consolidated financial statements for additional information.
- ZENS obligations are included in the 2029 column at their contingent principal amount of less than \$0.1 million as of December 31, 2025. These obligations are exchangeable for cash at any time at the option of the holders for 95% of the current value of the reference shares attributable to each ZENS (\$507 million as of December 31, 2025), as discussed in Note 10 to the consolidated financial statements.
- The Registrants calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, the Registrants calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, the Registrants used interest rates in place as of December 31, 2025. The Registrants typically expect to settle such interest payments with cash flows from operations and short-term borrowings.
- For a discussion of commodity and other commitments, see Note 14(a) to the consolidated financial statements.

The table above does not include the following:

- estimated future payments for expected future AROs primarily estimated to be incurred after 2030. See Note 3(c) to the consolidated financial statements for further information.

- expected contributions to pension plans and other postretirement plans in 2026 and expected benefit payments to be paid by the pension and postretirement benefit plans. See Note 8(g) to the consolidated financial statements for further information.
- operating leases. See Note 19 to the consolidated financial statements for further information.

Off-Balance Sheet Arrangements

Other than Houston Electric's general mortgage bonds issued as collateral for tax-exempt long-term debt of CenterPoint Energy as discussed in Note 12 and guarantees as discussed in Note 14(b) to the consolidated financial statements and short-term leases, the Registrants have no off-balance sheet arrangements.

Regulatory Matters

TEEEF (CenterPoint Energy and Houston Electric)

For information about TEEEF, see Note 7 to the consolidated financial statements.

Hurricane Beryl (CenterPoint Energy and Houston Electric)

For information about Hurricane Beryl, see Note 7 to the consolidated financial statements.

May 2024 Storm Events (CenterPoint Energy and Houston Electric)

For information about May 2024 Storm Events, see Note 7 to the consolidated financial statements.

February 2021 Winter Storm Event (CenterPoint Energy, Houston Electric and CERC)

For information about the February 2021 Winter Storm Event, see Note 7 to the consolidated financial statements.

Indiana Electric Securitization of Generation Retirements (CenterPoint Energy)

For further information about the issuance of SIGECO Securitization Bonds, see Note 7 to the consolidated financial statements.

Indiana Electric CPCN (CenterPoint Energy)

*BTA*s

Indiana Electric pursued PTCs for solar projects following the passage of the IRA. On February 7, 2023, Indiana Electric filed a CPCN with the IURC to approve an amended BTA to purchase the 191 MW Posey Solar project. Indiana Electric requested that project costs, net of PTCs, be recovered in rate base rather than a levelized rate, through base rates or the CECA mechanism, depending on which provides more timely recovery. On September 6, 2023, the IURC issued an order approving the CPCN. On March 7, 2025, SIGECO completed the acquisition of Posey Solar from Arevon for a purchase price of approximately \$357 million. The Posey Solar project was placed in service in the second quarter of 2025 and is currently being recovered through base rates. In the applicable rate case, the IURC approved Indiana Electric's request to convey PTCs to customers through the new tax adjustment rider. For further information, see Note 4 to the consolidated financial statements.

On January 10, 2023, Indiana Electric filed a CPCN with the IURC to acquire a wind energy generating facility located in the central region of MISO through a BTA, and on June 6, 2023, the IURC issued an order approving the CPCN, thereby authorizing Indiana Electric to purchase the wind generating facility. In August 2025, due to changing project considerations and concerns about customer affordability, Indiana Electric exited negotiations relating to this wind energy generating facility. On December 4, 2025, Indiana Electric filed a Notice of Termination in this proceeding.

*PPA*s

Indiana Electric sought approval in February 2021 for a 100 MW solar PPA with Clenera LLC in Warrick County, Indiana. The request accounted for increased cost of debt related to this PPA, which would provide equivalent equity return to offset imputed debt during the 25-year life of the PPA. In October 2021, the IURC approved the Warrick County solar PPA but denied the request to preemptively offset imputed debt in the PPA cost. Due to rising project costs caused by inflation and supply chain issues affecting the energy industry, Clenera LLC and Indiana Electric renegotiated the terms of the agreement to increase the PPA price and Indiana Electric subsequently filed a request with the IURC to amend the previously approved PPA with certain modifications. On May 30, 2023, the IURC approved the Warrick County solar amended PPA; however, due to MISO interconnection study delays and estimated interconnection cost increases, on April 24, 2025, Indiana Electric provided notice that it was exercising its right to terminate the PPA, which terminated all further obligations of Indiana Electric with respect to the project.

On August 25, 2021, Indiana Electric filed with the IURC seeking approval to purchase 185 MW of solar power, under a 15-year PPA, from Oriden, which is developing a solar project in Vermillion County, Indiana, and 150 MW of solar power, under a 20-year PPA, from Origis, which is developing a solar project in Knox County, Indiana. On May 4, 2022, the IURC issued an order approving Indiana Electric to enter into both PPAs. In March 2022, when the results of the MISO

interconnection study were completed, Origis advised Indiana Electric that the costs to construct the solar project in Knox County, Indiana had increased largely due to escalating commodity and supply chain costs impacting manufacturers worldwide. In August 2022, Indiana Electric and Origis entered into an amended PPA, which reiterated the terms contained in the 2021 PPA with certain modifications. On February 22, 2023, the IURC approved the Knox County solar amended PPA; however, due to MISO interconnection delays, the project in-service date has been delayed from 2024 to 2026. On January 17, 2023, Indiana Electric filed a request with the IURC to amend the previously approved PPA with Oriden with certain modifications. On May 30, 2023, the IURC approved the Vermillion County solar amended PPA; however, due to MISO interconnection study delays, the developer disclosed the project in-service date would be delayed to 2028. On May 9, 2025, Indiana Electric and Oriden terminated the PPA.

On May 1, 2024, Indiana Electric filed with the IURC seeking approval to purchase 147 MW of wind power under a 25-year PPA with an affiliate of NextEra Energy, Inc., which is developing a wind project in Knox County, Illinois. On November 6, 2024, the IURC approved the Knox County wind PPA, which provided for the recovery of the purchase power costs through the fuel adjustment clause proceedings over the term of the PPA. The facility is targeted to be in operation in late 2026.

On April 14, 2025, Indiana Electric filed with the IURC seeking approval to purchase 170 MW of wind power under a 25-year PPA with an affiliate of NextEra Energy, Inc., which is developing a wind project in Tama County, Iowa. On June 3, 2025, an amendment to the PPA was filed with the IURC requesting an extension of the PPA's term from 25 to 27 years. Indiana Electric received a final order from the IURC on November 5, 2025. The facility became operational on December 9, 2025. The power purchase costs will be recovered through the fuel adjustment clause proceedings over the term of the PPA.

Indiana Electric 2025 IRP (CenterPoint Energy)

On December 5, 2025, Indiana Electric submitted its 2025 IRP with the IURC pursuant to applicable Indiana law requiring electric utilities to develop and submit to the IURC every three years (unless extended) an IRP that uses economic modeling to consider the costs and risks associated with available generation resource options to provide reliable, cost effective electric service for the next 20-year period. Indiana Electric's 2025 IRP was developed following a series of public meetings and stakeholder discussions occurring in 2025 and identified both a preferred portfolio, which assumes the status quo for Indiana Electric's service territory, and an alternative preferred portfolio, which includes a potential large load addition. Due to the phasing out of IRA renewable energy tax incentives pursuant to the OBBBA, declining accreditation from MISO for renewable energy and increased price pressure on resources due to, among other things, tariffs and ongoing supply chain issues, the 2025 IRP extends the timing for Indiana Electric's generation transition plan. Accordingly, both the preferred portfolio and the alternative portfolio call for using the interconnection at F.B. Culley unit 2 for a 90 MW battery storage unit by 2028 and the conversion of the A.B. Brown units 5 and 6 gas turbines to a combined cycle gas turbine unit in the near- to mid-term, depending on load conditions. Decisions around F.B. Culley 3 will be reevaluated in the next IRP in 2028. The 2025 IRP includes the cancellation of nearly \$1 billion in non-economical renewable projects. For more information regarding the risks associated with Indiana Electric's execution of its generation transition plan and its IRP, see "Risk Factors - Risk Factors Affecting Operations - Indiana Electric's execution of its generation transition plan..."

F.B. Culley Unit 2 (CenterPoint Energy)

While Indiana Electric's 2025 IRP (similar to previous IRPs) preferred portfolios included the retirement of F.B. Culley Unit 2, a coal-fired generation unit, by the end of 2025, the U.S. Department of Energy issued an emergency 202(c) order in December 2025 directing Indiana Electric to continue operating the unit through March 23, 2026. Indiana Electric has filed a complaint with the FERC to request creation of a cost recovery/cost allocation mechanism. If created, a separate filing will be made at a later date with the FERC to seek recovery of all costs incurred to comply with the U.S. Department of Energy's emergency 202(c) order. Indiana Electric has also filed an application with the IURC in Cause No. 46350 to recover any compliance costs associated with the emergency 202(c) order that are not recovered through the FERC proceedings.

Natural Gas Combustion Turbines (CenterPoint Energy)

On June 17, 2021, Indiana Electric filed a CPCN with the IURC seeking approval to construct two natural gas combustion turbines to replace portions of its existing coal-fired generation fleet. On June 28, 2022, the IURC approved the CPCN. The \$287 million turbine facility was constructed at the previous site of the A.B. Brown power plant in Posey County, Indiana. Indiana Electric received approval for depreciation expense and post in-service carrying costs to be deferred in a regulatory asset until the date Indiana Electric's base rates include a return on and recovery of depreciation expense on the facility. A new approximately 23.5-mile pipeline was constructed and is operated by Texas Gas Transmission, LLC to supply natural gas to the turbine facility. FERC granted a certificate to construct the pipeline on October 20, 2022. On January 7, 2025, the United States Court of Appeals for the D.C. Circuit affirmed FERC's order granting the certificate. Indiana Electric granted its contractor a full notice to proceed to construct the turbines on December 9, 2022. In the second quarter of 2025, 230 MW of the facility was

placed in service, and, due to a transformer manufacturing issue, the remaining 230 MW of the facility was placed in service in the third quarter of 2025. Indiana Electric received approval from the IURC on February 3, 2025, to recover for each combustion turbine by adjusting base rates as they are placed in service. The first turbine and second turbine are currently being recovered in base rates that were updated on June 17, 2025 and October 1, 2025, respectively.

Stewart-West Bay Transmission Project (CenterPoint Energy and Houston Electric)

On April 30, 2025, Houston Electric filed a CCN application with the PUCT for approval to replace a portion of a 138 kV double circuit transmission line in Galveston County, Texas that connects Houston Electric's Stewart and West Bay substations. On June 27, 2025, an order was issued dismissing all opposing parties from the proceeding. On August 11, 2025, a notice of approval of Houston Electric's application was issued. The project is estimated to cost approximately \$105 million, but the actual capital cost of the project will depend on construction costs and other factors. Completion of construction and energization of the line is anticipated to occur in the third quarter of 2027.

Space City Solar Transmission Interconnection Project (CenterPoint Energy and Houston Electric)

On December 17, 2020, Houston Electric filed a CCN with the PUCT for approval to build a 345 kV transmission line in Wharton County, Texas connecting the Hillje substation on Houston Electric's transmission system to the planned 610 MW Space City Solar Generation facility being developed by third-party developer, EDF Renewables. In November 2021, the PUCT approved a route that was estimated to cost \$25 million and issued a final order on January 12, 2022. There have been project delays due to supply chain constraints in the developer acquiring solar panels. Houston Electric substantially completed construction in the fall of 2023, and the transmission line is expected to be energized shortly after the generation facility is complete, which is anticipated to occur in the first quarter of 2027.

Kilgore Transmission Project (CenterPoint Energy and Houston Electric)

On August 30, 2023, Houston Electric filed a CCN application with the PUCT for approval to build a 138 kV double circuit transmission line in Chambers County, Texas that will loop the existing 138 kV Chevron to Langston circuit number 86 on Houston Electric's transmission system to Houston Electric's planned Kilgore substation. On March 7, 2024, the PUCT issued a final order approving a route that was estimated to cost \$60 million, including substation costs. The actual capital costs of the project, including the transmission line and the planned Kilgore substation, will depend on actual land acquisition costs, construction costs, and other factors. Completion of construction and energization of the line and substation is anticipated to occur in the fourth quarter of 2026.

Mill Creek Transmission Project (CenterPoint Energy and Houston Electric)

On November 17, 2023, Houston Electric filed a CCN application with the PUCT for approval to build a 138 kV double circuit transmission line in Harris and Montgomery Counties, Texas that will connect Houston Electric's transmission system to Houston Electric's planned Mill Creek substation. On November 21, 2024, the PUCT issued a final order approving a route estimated to cost \$68 million. The actual capital costs of the project will depend on actual land acquisition costs, construction costs, and other factors. Completion of construction and energization of the line and substation is anticipated to occur in the second quarter of 2027.

Indiana Legislation (CenterPoint Energy)

Indiana Electric is evaluating legislation filed in Indiana's 124th General Assembly, including House Bill 1002, a multi-faceted bill aimed at improving the affordability of electric rates. House Bill 1002 would do the following:

- beginning in 2026, require an electric utility to file a multi-year rate plan according to a prescribed schedule;
- apply a customer affordability performance metric and a service restoration performance metric to each year of the multi-year rate plan and use such metric to provide financial rewards or penalties based on the electricity supplier's measured performance of the metric;
- require an electric utility to offer a low income customer assistance program by July 1, 2026 to be funded by at least 0.2% of jurisdictional revenues for residential customers and allow the utility to seek recovery of eligible program costs;
- prohibit an electric utility from terminating service to any customer on a day forecasted by the National Weather Service to have a heat index of at least 95 degrees Fahrenheit;
- modify the IURC's authority related to use of emergency powers;

- apply a leveled billing plan to residential customers who are eligible and have applied for the Low Income Housing Energy Assistance Program; and
- require an electric utility to report certain residential customer data to the Office of the Utility Consumer Counselor on a quarterly basis.

There are other bills moving through the 124th General Assembly, including legislation regarding surplus interconnection service, nuclear facility permits, and a bill on land use and developments that includes siting of battery energy storage systems.

Texas Legislation (CenterPoint Energy, Houston Electric and CERC)

The Registrants are evaluating the effects of certain legislation passed in 2025 and associated PUCT rulemaking projects, including the following pieces of legislation that became law during the 89th Texas Legislature:

- House Bill 4384, effective June 20, 2025, allows LDCs to recover post in-service carrying costs (PISCC) in GRIP filings. This allows LDCs to defer for future recovery as a regulatory asset PISCC, depreciation expense and ad valorem taxes associated with unrecovered gross plant.
- Senate Bill 231, effective June 20, 2025, provides that, on or after the effective date, TDUs may only enter into, renew or extend leases for TEEEF units with a maximum generation capacity 5 or fewer MW and that are rapidly deployable, and that they may enter into leases without prior PUCT preapproval (as required by the TEEEF Rule) in the case of an emergency or if the lease includes a provision allowing for the alteration of the lease based on applicable PUCT orders or rules.
- Senate Bill 1963, effective September 1, 2025, allows ERCOT utilities to securitize system restoration costs using a third-party government agency, which may allow for the debt to be off balance sheet and an abbreviated proceeding timeline. This bill also lowered the system restoration costs threshold from \$100 million to \$50 million, provided the effectiveness tests are met.
- Senate Bill 482, effective September 1, 2025, results in increased penalties for assaulting a utility worker to a third-degree felony, equal to assaulting a first responder, and for harassing a utility worker to a Class A misdemeanor.

Transmission and Distribution System Resiliency Plans (CenterPoint Energy and Houston Electric)

Following feedback from customers, external experts and other stakeholders, including elected officials and local agencies, Houston Electric filed a revised SRP with the PUCT on January 31, 2025 for review and approval. The filed SRP proposed to invest approximately \$5.75 billion over a three-year period from 2026 to 2028 for transmission and distribution infrastructure, information technology and cybersecurity assets and event response capability. This plan proposed 39 resiliency-enhancing measures and a microgrid pilot program to be implemented over the three-year period. The SRP as filed had an estimated capital cost of approximately \$5.54 billion and an estimated operations and maintenance expense of approximately \$211 million. Approximately \$2.17 billion of such cost was for transmission-related investments, and approximately \$3.58 billion was for distribution-related investments. Intervenor testimony was filed on April 8, 2025, and PUCT staff testimony was filed on April 15, 2025. On June 12, 2025, Houston Electric announced that it had reached a settlement agreement with parties to its SRP, which provides for approximately \$3.18 billion in distribution-related investments. The proposed transmission investments were removed from the SRP and Houston Electric intends to implement such investments, as appropriate, outside of the SRP process. The agreement also includes the deferral of more than \$240 million of the approximate \$3.18 billion in SRP costs until the second half of 2029, which is intended to help reduce the bill impact for customers by spreading costs over a four-year period instead of three years. Once approved, and while some cost recovery would be deferred into 2029, it is expected that all SRP work agreed upon in the settlement agreement will be completed in the proposed 2025 to 2028 timeframe. At its November 14, 2025 open meeting, the PUCT approved the SRP. The final order issued on November 19, 2025 includes twenty-seven resiliency measures totaling approximately \$2.68 billion in capital investments and an estimated \$185 million in operations and maintenance expense. The approved SRP also includes the deferral of \$217 million of the approximate \$2.87 billion in SRP costs until the second half of 2029.

Rate Change Applications

The Registrants are routinely involved in rate change applications before state regulatory authorities. Those applications include general rate cases, where the entire cost of service of the utility is assessed and reset. In addition, the Registrants are periodically involved in proceedings to adjust their capital tracking mechanisms (e.g., CSIA, DCRF, DRR, GRIP, TCOS, ECA, CECA and TDSIC), their decoupling mechanisms (e.g., decoupling and SRC), and their energy efficiency cost trackers (e.g., CIP, DSMA, EECRF, EEFC and EEFR).

Minnesota Gas Rate Case. On November 1, 2023, CERC filed an application with the MPUC requesting an adjustment to delivery charges in 2024 and 2025 for the natural gas business in Minnesota. The requested increase was for approximately

6.5% or \$85 million for 2024 and an additional approximately 3.7% or \$52 million for 2025. The need for a rate change was primarily driven by continuing investment in the safety and reliability of the natural gas system, including new Intelis natural gas meters that feature an integrated safety shutoff valve, changes to depreciation rates that better reflect the actual life and salvage characteristics of assets and changes in other costs to serve customers. The request reflected a proposed 10.3% ROE on a 52.5% equity ratio. Interim rates for 2024 of \$69 million, subject to refund, were implemented as of January 1, 2024. A request for interim rates of \$33 million for 2025 was filed on September 30, 2024, approved at the December 3, 2024 hearing and approved by an order issued December 20, 2024. A unanimous settlement agreement was filed on November 25, 2024 and provided for an increase of \$60.8 million for 2024 and an additional \$42.7 million for 2025. The parties agreed to an overall cost of capital of 7.07% for 2024 and 2025. The ALJ filed a report on February 13, 2025 recommending that the MPUC approve the settlement agreement. As required by the December 20, 2024 order, the difference between 2024 interim rates and the settled amount of \$60.8 million was refunded to customers in March 2025. Exceptions to the ALJ report were filed on April 18, 2025. On May 29, 2025, the MPUC approved the settlement agreement. A final order approving the settlement agreement was issued by the MPUC on June 27, 2025 and final rates were implemented on September 1, 2025.

Indiana Electric Rate Case. On December 5, 2023, Indiana Electric filed a petition with the IURC for authority to modify its rates and charges for electric utility service through a phase-in of rates. The requested increase was approximately 16% or \$119 million based on a forward looking 2025 test year. The need for a rate increase was primarily driven by the continuing investment in the safety and reliability of the system and normal increases in operating expenses. The initial filing of the rate case reflected a proposed 10.4% ROE on a forecasted 55% equity ratio. Indiana Electric reached a settlement agreement with less than all parties and submitted the agreement to the IURC on May 20, 2024. The settlement reflected a proposed 9.8% ROE on a forecasted 55% equity ratio. The requested increase was lowered to \$80 million, an 11% increase. Indiana Electric received a final order on February 3, 2025 approving the settlement with one modification that effectively capped the residential increase to 1.15% of the total increase, allocating the difference to other commercial and industrial customers. The final order approved the 9.8% ROE on a forecasted 55% equity ratio and increases revenues by \$80 million.

Houston Electric Rate Case. On March 6, 2024, Houston Electric filed an application with the PUCT requesting authority to change rates and charges for electric transmission and distribution service. The requested increase was approximately \$17 million (1%) for retail customers and \$43 million (6.6%) for wholesale transmission service, excluding TCRF and rate case expenses. The need for a rate increase was primarily driven by continuing investment that has been made to support customer growth and to bolster the safety and reliability of Houston Electric's transmission and distribution system. The request reflected a proposed 10.4% ROE and a 45% equity ratio. Errata testimony was filed to correct minor errors included in the initial filing, which reduced the requested increase to \$56 million compared to then-current rates. Houston Electric reached a settlement agreement with certain parties and submitted the agreement to the PUCT on January 29, 2025. The settlement reflected a \$47 million reduction in annual revenues and a 9.65% ROE and a weighted average cost of capital of 6.606% based upon an as-filed 4.29% cost of debt, an agreed ROE of 9.65% and an agreed regulatory capital structure of 56.75% long-term debt and 43.25% equity. A final order approving the settlement agreement was issued by the PUCT on March 13, 2025. Final retail delivery rates were implemented on April 28, 2025. Final wholesale transmission rates were superseded by interim TCOS rates that went into effect on the same date.

Ohio Gas Rate Case. CEOH filed its Application and Standard Filing Requirement in October 2024 and the related testimony in November 2024. The filing seeks a revenue requirement increase of approximately \$100 million based on a requested ROE of 10.4% and an equity percentage of 54.13%. The need for a rate increase was primarily driven by continuing investment in the safety and reliability of the natural gas system. On May 16, 2025, the PUCO staff filed its staff report recommending a revenue requirement range of \$340.8 million to \$350.3 million and a net increase of \$25.1 million to \$34.6 million based on an ROE range from 9.05% to 10.07% with a capitalization ratio of 52.3% common equity and 47.7% long-term debt. The PUCO staff recommendation includes amortization over 49 years and 65 years for CEP and DRR regulatory assets, respectively, compared to CEOH's proposal to amortize over seven years. On June 16, 2025, CEOH filed objections to the PUCO staff report and supplemental testimony. On July 11, 2025, CEOH filed a stipulation and recommendation that outlined the agreed upon terms between CEOH, the Federal Executive Agencies, Ohio Energy Group, the City of Dayton, the Retail Energy Supply Association, Interstate Gas Supply, LLC and the PUCO staff. One intervening party to the case, Spire Marketing, Inc., is a non-opposing party, while another intervening party to the case, the Office of the Ohio Consumers' Counsel, filed its testimony in opposition to the stipulation and recommendation on July 29, 2025. The stipulation and recommendation included a revenue requirement of \$371.3 million, which would result in a revenue requirement increase of \$59.6 million based on a rate of return of 7.1% comprised of a ROE of 9.85% with a capitalization ratio of 52.9% common equity, 47.1% long-term debt at a cost of debt of 4.02%. The stipulation and recommendation amortization periods for CEP and DRR regulatory assets within base rates and within the rider mechanisms is 15 years. The stipulation and recommendation included an extension of the CEP rider and DRR through 2029 investment with revised residential caps for dollars per month per customer ranging from \$2.75 for 2025 investment to \$9.95 for 2029 investment for the CEP rider, and from \$2.56 for 2025 investment to \$7.69 for 2029 investment for DRR. The evidentiary hearing commenced on July 21, 2025. The stipulating parties were crossed by the Office of the Ohio Consumers' Counsel on July 28 and August 4, 2025, and the Office of the Ohio

Consumers' Counsel was crossed by the stipulating parties on July 29 and August 5, 2025. On July 29, 2025, a PUCO local public hearing was conducted. The parties filed initial briefs on August 26, 2025, and reply briefs on September 9, 2025. On November 21, 2025, CEOH filed a late filed exhibit to the stipulation and recommendation to include actual rate case expenses, which resulted in a revised revenue requirement increase of \$59.7 million. The PUCO order was issued on January 7, 2026, modifying and adopting the stipulation and resolving all issues related to the case. The PUCO order modifications include: (1) extending the 15-year amortization periods for the CEP and DRR deferral balances to 25 years, which had a \$7.9 million negative impact on the revenue requirement, and (2) a ROE of 9.79%, resulting in a rate of return of 7.07%, which had a \$0.6 million negative impact on the revenue requirement. These two modifications result in a revised revenue requirement increase of \$51.3 million and a total revenue requirement of \$363 million. Revised rates became effective on a services rendered basis effective January 12, 2026.

The table below reflects significant applications pending or completed since the Registrants' combined 2024 Form 10-K was filed with the SEC through the date of the filing of this Form 10-K:

Mechanism	Annual Increase (Decrease) (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
CenterPoint Energy and Houston Electric (PUCT)					
Rate Case	\$ (47)	March 2024	April 2025	March 2025	See discussion above under <i>Houston Electric Rate Case</i> .
TCOS	\$ 64	February 2025	April 2025	April 2025	Based on the net change in invested capital since its last base rate proceeding of approximately \$614 million for the period January 1, 2024 through December 31, 2024.
DCRF	\$ 123	February 2025	July 2025	June 2025	Based on the net change in distribution invested capital since its last base rate proceeding of approximately \$1 billion for the period January 1, 2024 through December 31, 2024, for an incremental revenue increase of \$123 million adjusted for load growth.
TEEEF	\$ (24)	April 2025	TBD	TBD	Seeks approval of: (1) the release of Houston Electric's 15 large 32 MW TEEEF units to ERCOT at CPS Energy facilities to serve the greater San Antonio region until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction; (2) a corresponding reduction to the capacity of the Houston Electric TEEEF fleet; and (3) a reduction and update to Houston Electric's rider TEEEF rate to reflect the removal of the 15 large 32 MW TEEEF units from Houston Electric's TEEEF fleet. Houston Electric will make no revenue or profit from ERCOT for the time period when the 15 large 32 MW TEEEF units are in the San Antonio area being dispatched by ERCOT. In November 2025, Houston Electric also proposed to release the five medium 5.7 MW TEEEF units from its TEEEF fleet and remove the associated lease costs effective January 1, 2026. On February 13, 2026, Houston Electric filed a letter requesting continued abatement until February 27, 2026 due to continued settlement discussions.
TEEEF	N/A	May 2025	TBD	TBD	Seeks authorization to lease small, 200 kW to 1,250 kW TEEEF units for 36 months in accordance with the TEEEF Rule. Among other things, the TEEEF Rule generally requires that a utility obtain preapproval prior to renewing or entering into a new lease of TEEEF units, with exceptions for emergency situations or if the lease includes a provision allowing for the alteration of the lease based on applicable PUCT orders or rules. Approval of Houston Electric's request in this filing will have no cost impact on customers at this time, as cost determination will occur in a future proceeding. On January 6, 2026, Houston Electric provided the PUCT with a proposed order.
EECRF	\$ 40	May 2025	March 2026	December 2025	Requests \$96 million, which is comprised primarily of the following: 2026 program costs of \$50 million; \$5 million related to the under-recovery of 2024 program costs; the 2024 earned bonus of \$40 million; and 2026 projected evaluation, measurement and verification costs of \$0.6 million. On September 8, 2025, the Sierra Club filed direct testimony. On September 19, 2025, the PUCT staff filed its recommendation requesting that SOAH approve the application as filed. On October 3, 2024, the PUCT staff petitioned (Docket No. 57172) to establish a secondary cap on utilities' 2024 Program Year (PY) earned performance bonuses equal to 25% of utilities' total expenditures for PY 2024, and on August 13, 2025, the PUCT issued a final order denying the PUCT staff's petition. On October 7, 2025, Houston Electric filed an unanimous stipulation and settlement agreement for the full amount requested. On October 10, 2025, SOAH remanded this proceeding to the PUCT. A final order approving the settlement agreement was issued on December 12, 2025.
TCOS	\$ 15	August 2025	October 2025	October 2025	Based on the net change in invested capital since its last TCOS proceeding of approximately \$112 million for the period January 1, 2025 through June 30, 2025.
DCRF	\$ 55	August 2025	December 2025	October 2025	Based on the net change in distribution invested capital since its last base rate proceeding of approximately \$1.5 billion for the period January 1, 2024 through June 30, 2025 for an incremental revenue increase of \$55 million adjusted for load growth.

Mechanism	Annual Increase (Decrease) (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
TCOS	\$ 36	February 2026	TBD	TBD	Based on the net change in invested capital since its last TCOS proceeding of approximately \$212 million for the period of July 1, 2025 through December 31, 2025, along with the inclusion of regulatory assets of approximately \$10 million comprising certain system restoration operations and maintenance expenses and carrying costs associated with the May 2024 Storm Events and Hurricane Beryl.
CenterPoint Energy and CERC - Beaumont/East Texas, South Texas, Houston and Texas Coast (Railroad Commission)					
Tax Act Rider	\$ 15	August 2024	June 2025	May 2025	Resulting from the Texas Gas Rate Case, the first Tax Act Rider Calculation was filed on August 1, 2024 pursuant to Docket No. OS-23-00015513 to recover the effects of the IRA and certain other tax-related costs for rates that became effective January 1, 2025. These effects include the return on the CAMT deferred tax asset ("DTA") resulting from the IRA, income tax credits resulting from the IRA and the return on the increment or decrement in the net operating loss DTA included in the rate base and in the standard service base revenue requirement approved in the Texas Gas Rate Case. CERC believes its filing is consistent with the Tax Act Rider tariff approved in Docket No. OS-23-00015513. On October 1, 2024, certain parties filed comments disputing the application. Briefings were filed with an ALJ in November 2024. A hearing on the merits was held on February 21, 2025 and continued on March 21, 2025. On March 21, 2025, a unanimous settlement agreement was filed. On April 11, 2025, a PFD was issued. On May 13, 2025, the Railroad Commission considered the PFD at an open meeting and issued a Final Order approving the settlement agreement.
Tax Act Rider	\$ 22	August 2025	January 2026	October 2025	The second Tax Act Rider was initially filed on August 1, 2025, and a revised filing was made on September 24, 2025, to recover the effects of the IRA and certain other tax-related costs for rates that would be effective for bills calculated on or after January 1, 2026. These effects include the return on the CAMT DTA resulting from the IRA, income tax credits resulting from the IRA and the return on the increment or decrement in the net operating loss DTA included in the rate base and in the standard service base revenue requirement approved in the Texas Gas Rate Case Docket No. OS-23-00015513. No comments from the parties were filed prior to the October 1, 2025 deadline for comments. The Railroad Commission accepted the Tax Act Rider filing on October 16, 2025.
GRIP	\$ 70	February 2025	June 2025	May 2025	Based on net change in invested capital of \$445 million.
GRIP	\$ 62	February 2026	TBD	TBD	Based on net change in invested capital of \$394 million.
CenterPoint Energy and CERC - Minnesota (MPUC)					
Rate Case	\$ 104	November 2023	September 2025	July 2025	See discussion above under <i>Minnesota Gas Rate Case</i> .
CIP Financial Incentive	\$ 8	May 2025	December 2025	November 2025	CIP Financial Incentive based on 2024 CIP program activity.
CenterPoint Energy - Indiana South - Gas (IURC)					
CSIA	\$ 2	April 2025	August 2025	July 2025	Requested an increase of \$11.6 million to rate base, which reflects an approximately \$1.5 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under recovery variance of \$1.9 million. The OUCC filed testimony on June 3, 2025, recommending minor changes. Indiana South filed a rebuttal on June 17, 2025, adopting the changes. The evidentiary hearing was held on June 30, 2025. A final order was issued on July 30, 2025, with rates effective August 1, 2025.
CSIA	\$ 1	October 2025	February 2026	January 2026	Requested an increase of \$13.0 million to rate base, which reflects an approximately \$1.2 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under recovery variance of \$(2.1) million. The OUCC filed testimony on December 2, 2025, recommending minor changes, and Indiana South filed rebuttal on December 16, 2025. An evidentiary hearing was held January 6, 2026. A final order was issued on January 28, 2026 with rates effective on February 1, 2026.
CenterPoint Energy and CERC - Indiana North - Gas (IURC)					
CSIA	\$ 9	April 2025	August 2025	July 2025	Requested an increase of \$94.9 million to rate base, which reflects an approximately \$8.6 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under recovery variance of \$5 million. The OUCC filed testimony on June 3, 2025. Indiana North filed rebuttal testimony on June 17, 2025. The evidentiary hearing was held on June 30, 2025. A final order was issued on July 30, 2025, with rates effective August 1, 2025.

Mechanism	Annual Increase (Decrease) (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
CSIA	\$ 8	October 2025	February 2026	January 2026	Requested an increase of \$90.8 million to rate base, which reflects an approximately \$7.6 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under recovery variance of \$(6.8) million. The OUCC filed testimony on December 2, 2025, recommending minor changes, and Indiana North filed rebuttal on December 16, 2025. An evidentiary hearing was held January 6, 2026. A final order was issued on January 28, 2026, with rates effective on February 1, 2026. On February 17, 2026, the OUCC filed a motion for rehearing and reconsideration requesting the commission to reconsider its decision approving the recovery of soil remediation costs from ratepayers and reconsider the threshold for a best estimate for a TDSIC plan and the specific justification the commission will require to increase an approved best estimate.
CenterPoint Energy and CERC - Ohio - Gas (PUCO)					
DRR	\$ 6	May 2025	September 2025	August 2025	Requested an increase of \$54 million to rate base for investments made in 2024, which reflects a \$6 million annual increase in current revenues. A change in (over)/under-recovery variance of \$(0.03) million annually is also included in rates. PUCO staff and intervenor (Ohio Consumers' Counsel) filed comments June 27, 2025. PUCO staff recommended approval. Ohio Consumers' Counsel commented on affordability and provided potential solutions including stretching out the replacement program over a longer period of time, phasing in the annual increase, shifting from fixed charges to volumetric charges, and increasing funding for its bill assistance programs. A statement informing the PUCO of whether the issues raised in comments have been resolved was filed on July 11, 2025. Supplemental Testimony from CEOH and the Ohio Consumers' Counsel was filed on July 22, 2025. A hearing was scheduled for July 29, 2025, with all parties waiving motions to strike, objections, and cross examination. A final PUCO opinion and order was issued on August 20, 2025, finding that the updated DRR rates are just and reasonable and stating that the correct forum for the Ohio Consumers' Counsel's arguments was the 2018 Rate Case, the 2022 Extension, or the 2024 Rate Case. Revised rates became effective on September 1, 2025.
Rate Case	\$ 51	October 2024	January 2026	January 2026	See discussion above under <i>Ohio Gas Rate Case</i> .

(1) Represents proposed increases (decreases) when effective date and/or approval date is not yet determined. Approved rates could differ materially from proposed rates.

GHG Emissions and Climate-Related Regulation and Compliance (CenterPoint Energy)

The issue of climate change has received focus at the state, federal and international level, and there are trends and uncertainties relating to GHG emissions and climate-related regulations and compliance that affect the Registrants. Compliance costs and other effects associated with climate change, reductions in GHG emissions and obtaining renewable energy sources remain uncertain; nevertheless, any new regulation or legislation relating to climate change will likely result in an increase in compliance costs. CenterPoint Energy will continue to monitor regulatory activity regarding GHG emission standards that may affect its business. Currently, CenterPoint Energy does not purchase carbon credits. In connection with its energy transition goals, CenterPoint Energy is expected to purchase carbon credits in the future; however, CenterPoint Energy does not currently expect the number of credits, or cost for those credits, to be material. For more information on GHG emissions and climate-change regulation and compliance, see "Business—Environmental Matters" in Item 1 of Part I of this report. For more information on GHG emissions and climate-related risk trends and uncertainties, see "Risk Factors" in Item 1A of Part I of this report.

Climate Risk Trends and Uncertainties

There are climate risk trends and uncertainties that affect the Registrants. Changes in the U.S. presidential administration and significant expected increases in electric demand, as announced by organizations such as ERCOT and MISO, have shifted the energy landscape in the United States. This shift in federal domestic energy policy has resulted in uncertainty with respect to the scope and speed of future renewable generation infrastructure development and the role that existing renewable generation will play in support of the U.S. energy grid. The long-term impacts of this domestic energy policy shift are also uncertain, including with respect to impacts on the development of, and consequently the availability of, alternative energy sources (such as solar energy, including private solar, wind energy, microturbines, fuel cells, energy-efficient buildings and energy storage devices). Additionally, it is unclear whether, and if so how, the new domestic energy policy, including the potential suspension, revision or rescission of regulations restricting emissions (including methane emissions) and the repeal of the Endangerment Finding, will affect consumers' and companies' energy use, adoption of alternative energy sources or decisions to expand their facilities, including natural gas facilities. For more information on climate risk trends and uncertainties, see "Risk Factors" in Item 1A of Part I of this report.

Other Matters

Credit Facilities

The Registrants may draw on their respective revolving credit facilities from time to time to provide funds used for general corporate and limited liability company purposes, including to backstop CenterPoint Energy's and CERC's commercial paper programs. The facilities may also be utilized to obtain letters of credit. For further details related to the Registrants' revolving credit facilities, see Note 12 to the consolidated financial statements.

Based on the consolidated debt to capitalization covenant in the Registrants' revolving credit facilities, the Registrants would have been permitted to utilize the full capacity of such revolving credit facilities, which aggregated approximately \$4.0 billion as of December 31, 2025. As of February 13, 2026, the Registrants had the following revolving credit facilities and utilization of such facilities:

Registrant	Size of Facility	Amount Utilized as of February 13, 2026			Weighted Average Interest Rate	Termination Date
		Loans	Letters of Credit	Commercial Paper		
		(in millions)				
CenterPoint Energy	\$ 2,400	\$ —	\$ —	\$ 665	3.75%	December 6, 2028
CenterPoint Energy (1)	250	—	—	—	—%	December 6, 2028
Houston Electric	300	—	—	—	—%	December 6, 2028
CERC	1,050	—	—	340	3.75%	December 6, 2028
Total	\$ 4,000	\$ —	\$ —	\$ 1,005		

(1) This credit facility was issued by SIGECO.

Borrowings under each of the revolving credit facilities are subject to customary terms and conditions. However, there is no requirement that the borrower makes representations prior to borrowing as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under each of the revolving credit facilities are subject to acceleration upon the occurrence of events of default that we consider customary. The revolving credit facilities also provide for customary fees, including commitment fees, administrative agent fees, fees in respect of letters of credit and other fees. In each of the revolving credit facilities, the spread to SOFR and the commitment fees fluctuate based on the borrower's credit rating. Each of the Registrant's credit facilities provide for a mechanism to replace SOFR with possible alternative benchmarks upon certain benchmark replacement events. The Registrants and SIGECO are currently in compliance with the various business and financial covenants in the four revolving credit facilities.

Debt Transactions

For detailed information about the Registrants' debt transactions in 2025, see Note 12 to the consolidated financial statements. For detailed information about the delay draw term loan agreement executed by CERC Corp. in 2026, see Note 20 to the consolidated financial statements.

Securities Registered with the SEC

On May 17, 2023, the Registrants filed a joint shelf registration statement with the SEC registering indeterminate principal amounts of Houston Electric's general mortgage bonds, CERC Corp.'s senior debt securities and CenterPoint Energy's senior debt securities and junior subordinated debt securities and an indeterminate number of shares of Common Stock, shares of preferred stock, depositary shares, as well as stock purchase contracts and equity units. The joint shelf registration statement will expire on May 17, 2026. For information related to the Registrants' debt issuances in 2025, see Note 12 to the consolidated financial statements.

For information related to shares of Common Stock sold pursuant to the forward sale agreements and the Equity Distribution Agreement in 2025, see Note 11 to the consolidated financial statements.

Money Pool

The Registrants participate in a money pool through which they and certain of their subsidiaries can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net

funding requirements of the CenterPoint Energy money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. The net funding requirements of the CERC money pool are expected to be met with borrowings under CERC's revolving credit facility or the sale of CERC's commercial paper. The money pool may not provide sufficient funds to meet the Registrants' cash needs.

The table below summarizes CenterPoint Energy money pool activity by Registrant as of February 13, 2026:

	Weighted Average Interest Rate	Houston Electric	CERC
		(in millions)	
Money pool borrowings	3.80%	\$ 463	\$ —

Impact on Liquidity of a Downgrade in Credit Ratings

The interest rate on borrowings under the Registrants' credit facilities is based on their respective credit ratings. As of February 13, 2026, Moody's, S&P and Fitch had assigned the following credit ratings to the borrowers:

Registrant	Borrower/Instrument	Moody's		S&P		Fitch	
		Rating	Outlook (1)	Rating	Outlook (2)	Rating	Outlook (3)
CenterPoint Energy	CenterPoint Energy Senior Unsecured Debt	Baa2	Negative	BBB	Stable	BBB	Stable
CenterPoint Energy	Vectren Corp. Issuer Rating	n/a	n/a	BBB+	Stable	n/a	n/a
CenterPoint Energy	SIGECO Senior Secured Debt	A1	Stable	A	Stable	n/a	n/a
Houston Electric	Houston Electric Senior Secured Debt	A2	Negative	A	Stable	A	Stable
CERC	CERC Corp. Senior Unsecured Debt	A3	Stable	BBB+	Stable	A-	Stable
CERC	Indiana Gas Senior Unsecured Debt	n/a	n/a	BBB+	Stable	n/a	n/a

- (1) A Moody's rating outlook is an opinion regarding the likely direction of an issuer's rating over the medium term.
- (2) An S&P outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term.
- (3) A Fitch rating outlook indicates the direction a rating is likely to move over a one- to two-year period.

The Registrants cannot assure that the ratings set forth above will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. The Registrants note that these credit ratings are included for informational purposes and are not recommendations to buy, sell or hold the Registrants' securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of the Registrants' credit ratings could have a material adverse impact on the Registrants' ability to obtain short- and long-term financing, the cost of such financings and the execution of the Registrants' commercial strategies.

A decline in credit ratings could increase borrowing costs under the Registrants' revolving credit facilities. If the Registrants' credit ratings had been downgraded one notch by S&P and Moody's from the ratings that existed as of December 31, 2025, the impact on the borrowing costs under the four revolving credit facilities would have been insignificant. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact the Registrants' ability to complete capital market transactions and to access the commercial paper market. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of CenterPoint Energy's and CERC's Natural Gas reportable segments.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecovered cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, CERC might need to provide cash or other collateral of up to \$311 million as of December 31, 2025. The amount of collateral will depend on seasonal variations in transportation levels.

ZENS and Securities Related to ZENS (CenterPoint Energy)

If CenterPoint Energy's creditworthiness were to drop such that ZENS holders thought CenterPoint Energy's liquidity was adversely affected or the market for the ZENS were to become illiquid, some ZENS holders might decide to exchange their ZENS for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of ZENS-Related Securities that CenterPoint Energy owns or from other sources. CenterPoint Energy owns shares of ZENS-Related Securities

equal to approximately 100% of the reference shares used to calculate its obligation to the holders of the ZENS. ZENS exchanges result in a cash outflow because tax deferrals related to the ZENS and shares of ZENS-Related Securities would typically be reversed when ZENS are exchanged or otherwise retired and shares of ZENS-Related Securities are sold. The ultimate tax liability related to the ZENS and ZENS-Related Securities continues to increase by the amount of the tax benefit realized each year, and there could be a significant cash outflow when the taxes are paid as a result of the retirement or exchange of the ZENS. If all ZENS had been exchanged for cash on December 31, 2025, deferred taxes of approximately \$897 million would have been payable in 2025, subject to reduction on account of any available net operating loss carryforwards or CAMT carryforwards. If all the ZENS-Related Securities had been sold on December 31, 2025, capital gains taxes of approximately \$72 million would have been payable in 2025 based on 2025 tax rates in effect and subject to reduction on account of any available net operating loss carryforwards or CAMT carryforwards. As of December 31, 2025, CenterPoint Energy had both net operating loss and CAMT carryforwards available from its filed 2024 federal income tax return that can be applied to largely offset the cash outflow that would result from a retirement or exchange of the ZENS. For additional information about ZENS, see Note 10 to the consolidated financial statements.

Cross Defaults

Under the Registrants' respective revolving credit facilities, a payment default on, or a non-payment default, event or condition that permits acceleration of, any indebtedness for borrowed money and certain other specified types of obligations (including guarantees) exceeding \$125 million by the borrower or any of their respective significant subsidiaries will cause a default under such borrower's respective credit facility or term loan agreement. Under SIGECO's revolving credit facility, a payment default on, or a non-payment default, event or condition that permits acceleration of, any indebtedness for borrowed money and certain other specific types of obligations (including guarantees) exceeding \$75 million by SIGECO or any of its significant subsidiaries will cause a default under SIGECO's credit facility. A default by CenterPoint Energy would not trigger a default under its subsidiaries' debt instruments or revolving credit facilities.

Possible Acquisitions, Divestitures and Joint Ventures

From time to time, the Registrants consider the acquisition or the disposition of assets or businesses or possible joint ventures, strategic initiatives or other joint ownership arrangements with respect to assets or businesses. Any determination to take action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. The Registrants may seek to fund all or part of any such efforts with proceeds from debt and/or equity issuances. Debt or equity financing may not, however, be available to the Registrants at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions. As announced in September 2025 and February 2026, CenterPoint Energy has increased its planned capital expenditures in its Electric and Natural Gas businesses pursuant to its new 10-year capital plan, which calls for investment of at least \$65.5 billion through 2035, and CenterPoint Energy may continue to increase such planned capital investments in the future. The Registrants may continue to explore asset sales, in addition to the completed sale of CERC Corp.'s Louisiana and Mississippi natural gas LDC businesses, as a means to efficiently finance a portion of their increased capital expenditures in the future, subject to the considerations listed above. For further information, see Note 4 to the consolidated financial statements.

On October 20, 2025, CenterPoint Energy, through CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH for total consideration of approximately \$2.62 billion, subject to adjustment as set forth in the Ohio Securities Purchase Agreement. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

Collection of Receivables from REPs (CenterPoint Energy and Houston Electric)

Houston Electric's receivables from the distribution of electricity are collected from REPs that supply the electricity Houston Electric distributes to their customers. Before conducting business, a REP must register with the PUCT and must meet certain financial qualifications. Nevertheless, adverse economic conditions, weather events, such as the February 2021 Winter Storm Event, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for Houston Electric's services or could cause them to delay such payments. Houston Electric depends on these REPs to remit payments on a timely basis, and any delay or default in payment by REPs could adversely affect Houston Electric's cash flows. In the event of a REP's default, Houston Electric's tariff provides a number of remedies, including the option for Houston Electric to request that the PUCT suspend or revoke the certification of the REP. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely

payments. However, Houston Electric remains at risk for payments related to services provided prior to the shift to the replacement REP or the provider of last resort. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations and claims might be made against Houston Electric involving payments it had received from such REP. If a REP were to file for bankruptcy, Houston Electric may not be successful in recovering accrued receivables owed by such REP that are unpaid as of the date the REP filed for bankruptcy. However, PUCT regulations authorize utilities, such as Houston Electric, to defer bad debts resulting from defaults by REPs for recovery in future rate cases, subject to a review of reasonableness and necessity.

Other Factors that Could Affect Cash Requirements

In addition to the above factors, the Registrants' liquidity and capital resources could also be negatively affected by:

- cash collateral requirements that could exist in connection with certain contracts, including weather hedging arrangements, and natural gas purchases, natural gas price and natural gas storage activities of CenterPoint Energy's and CERC's Natural Gas reportable segment;
- acceleration of payment dates on certain gas supply contracts, under certain circumstances, as a result of increased natural gas prices, and concentration of natural gas suppliers (CenterPoint Energy and CERC);
- increased costs related to the acquisition of natural gas (CenterPoint Energy and CERC);
- increased costs of certain goods, materials or services due to, among other things, supply chain disruptions, inflation, labor shortages, scarcity of materials and changes in U.S. or foreign trade policy (including tariffs or other trade actions);
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities or term loans or the use of alternative sources of financings, including financings due to the May 2024 Storm Events and Hurricane Beryl;
- various legislative, executive or regulatory actions at the federal, state and local levels, including actions in response to Hurricane Beryl and actions pertaining to U.S. or foreign trade policy (including tariffs or other trade actions) or other geopolitical matters;
- incremental collateral, if any, that may be required due to regulation of derivatives (CenterPoint Energy);
- the timing and outcome of rate actions regarding our recovery of costs and ability to make a reasonable return on investment;
- the ability of REPs, including REP affiliates of NRG and Vistra Energy Corp., to satisfy their obligations to CenterPoint Energy and Houston Electric;
- slower customer payments and increased write-offs of receivables due to higher natural gas prices, changing economic conditions, public health threats or severe weather events, such as the May 2024 Storm Events and Hurricane Beryl;
- the satisfaction of any obligations pursuant to guarantees;
- the outcome of litigation, including litigation related to the February 2021 Winter Storm Event and Hurricane Beryl;
- contributions to pension and postretirement benefit plans;
- recovery of any losses under applicable insurance policies;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes or other severe weather events and the timing of and amounts sought for recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Part I, Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money

Certain provisions in certain note purchase agreements relating to debt issued by CERC have the effect of restricting the amount of secured debt issued by CERC and debt issued by subsidiaries of CERC Corp. Additionally, Houston Electric and SIGECO are limited in the amount of mortgage bonds they can issue by the General Mortgage and SIGECO's mortgage indenture, respectively. For information about the total debt to capitalization financial covenants in the Registrants' and SIGECO's revolving credit facilities, see Note 12 to the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the Registrants' financial statements in conformity with GAAP requires management to apply appropriate accounting policies and to make estimates and judgments that can have a significant effect on the Registrants' financial condition, results of operations or cash flows. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. The Registrants base their estimates on historical experience and on various other assumptions that they believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired,

as additional information is obtained and as the Registrants' operating environment changes. Our management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board. For a complete discussion of the Registrants' significant accounting policies, see Note 2 to the consolidated financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. CenterPoint Energy, for its Electric and Natural Gas reportable segments, Houston Electric and CERC apply this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, the Registrants would be required to write off or write down these regulatory assets and liabilities. For further detail on the Registrants' regulatory assets and liabilities, see Note 7 to the consolidated financial statements.

Impairment of Long-Lived Assets, Including Goodwill

The Registrants review the carrying value of long-lived assets, including goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually, goodwill is tested for impairment as required by accounting guidance for goodwill. Unforeseen events, changes in market conditions, and probable regulatory disallowances, where applicable, could have a material effect on the value of long-lived assets, including goodwill, future cash flows, interest rate, and regulatory matters, and could result in an impairment charge. The Registrants recorded no impairments to long-lived assets, including goodwill during 2025, 2024 and 2023.

Fair value is the amount at which an asset, liability or business could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value could be different using different estimates and assumptions in these valuation techniques.

Fair value measurements require significant judgment and unobservable inputs, including (i) projected timing and amount of future cash flows, which factor in planned growth initiatives, (ii) the regulatory environment, as applicable, and (iii) discount rates reflecting risk inherent in the future market prices. Determining the discount rates for the businesses that are not rate-regulated, such as for Energy Systems Group prior to the sale in June 2023, requires the estimation of the appropriate company-specific risk premiums for such businesses based on evaluation of industry and entity-specific risks, which includes expectations about future market or economic conditions existing on the date of the impairment test. Changes in these assumptions could have a significant impact on results of the impairment tests.

Annual Goodwill Impairment Test

CenterPoint Energy and CERC completed their 2025 annual goodwill impairment test during the third quarter of 2025 and determined, based on a qualitative assessment, that no goodwill impairment charge was required for any reporting unit. No qualitative factors were present that indicated impairment of CenterPoint Energy or CERC reporting units.

Although no goodwill impairment resulted from the 2025 annual test, an interim goodwill impairment test could be triggered by the following: actual earnings results that are materially lower than expected, significant adverse changes in the operating environment, an increase in the discount rate, changes in other key assumptions which require judgment and are forward looking in nature, if CenterPoint Energy's market capitalization falls below book value for an extended period of time, or events affecting a reporting unit such as a contemplated disposal of all or part of a reporting unit.

Assets Held for Sale

Generally, a long-lived asset to be sold is classified as held for sale in the period in which management, with approval from the Board, as applicable, commits to a plan to sell, and a sale is expected to be completed within one year. The Registrants

record assets and liabilities held for sale, or the disposal group, at the lower of their carrying value or their fair value less cost to sell. If the disposal group reflects a component of a reporting unit and meets the definition of a business, the goodwill within that reporting unit is allocated to the disposal group based on the relative fair value of the components representing a business that will be retained and disposed. Goodwill is not allocated to a portion of a reporting unit that does not meet the definition of a business.

As of December 31, 2025, certain assets and liabilities of the Ohio natural gas LDC business met the held for sale criteria and the goodwill attributable to these businesses was \$393 million and \$219 million for CenterPoint Energy and CERC, respectively. As of December 31, 2024, certain assets and liabilities of the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria and the goodwill attributable to these businesses was \$217 million and \$122 million for CenterPoint Energy and CERC, respectively. See Note 4 for additional detail.

Accounting for Securitizations

Accounting guidance for rate regulated long-lived asset abandonment requires that the carrying value of an operating asset or an asset under construction is removed from property, plant and equipment when it becomes probable that the asset will be abandoned. The Registrants recognize a loss on abandonment when they conclude it is probable the cost will not be recovered in future rates. When the Registrants conclude it is probable that costs will be recovered in future rates, a regulatory asset is recognized. The portion of property, plant and equipment that will remain used and useful until abandonment and recovered through depreciation expense in rates will continue to be classified as property, plant and equipment until the asset is abandoned. The Registrants evaluate if an adjustment to the estimated life of the asset and, accordingly, the rate of depreciation, is required to recover the asset while it is still providing service. Determining probability of abandonment or probability of recovery requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals.

In connection with the securitization of transition property or system restoration property or to facilitate the securitization financing of qualified costs, CenterPoint Energy, Houston Electric and SIGECO evaluate the wholly-owned, bankruptcy-remote, special purpose entities, which are VIEs, for possible consolidation, including review of qualitative factors such as the power to direct the activities of the VIE and the obligation to absorb losses of the VIE. CenterPoint Energy, Houston Electric and SIGECO have the power to direct the significant activities of their respective VIEs and are most closely associated with their respective VIEs as compared to other interests held by the holders of the relevant Securitization Bonds. CenterPoint Energy, Houston Electric and SIGECO are, therefore, considered the respective primary beneficiary and consolidate these VIEs.

Unbilled Revenues

Revenues related to electricity delivery and natural gas sales and services are generally recognized upon delivery to customers. However, the determination of deliveries to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month either electronically through AMS meter communications or manual readings. At the end of each month, deliveries to non-AMS customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Information regarding deliveries to AMS customers after the last billing is obtained from actual AMS meter usage data. Unbilled electricity delivery revenue is estimated each month based on actual AMS meter data, daily supply volumes and applicable rates. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Employee Benefit Plans

CenterPoint Energy sponsors pension and other retirement plans in various forms covering all employees who meet eligibility requirements. CenterPoint Energy uses several statistical and other factors that attempt to anticipate future events in calculating the expense and liability related to its plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, CenterPoint Energy's actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the

amount of pension and other retirement plans expense recorded. Read “— Other Significant Matters — Pension Plans” for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(p) to the consolidated financial statements, incorporated herein by reference, for a discussion of new accounting pronouncements that affect the Registrants.

OTHER SIGNIFICANT MATTERS

Pension Plans (CenterPoint Energy). As discussed in Note 8(b) to the consolidated financial statements, CenterPoint Energy maintains non-contributory qualified defined benefit pension plans covering eligible employees. Employer contributions for the qualified plans are based on actuarial computations that establish the minimum contribution required under ERISA and the maximum deductible contribution for income tax purposes.

Under the terms of CenterPoint Energy’s pension plans, it reserves the right to change, modify or terminate the plan. CenterPoint Energy’s funding policy is to review amounts annually and contribute an amount at least equal to the minimum contribution required under ERISA.

Additionally, CenterPoint Energy maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under the non-contributory qualified pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated.

CenterPoint Energy’s funding requirements and employer contributions were as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
CenterPoint Energy	(in millions)		
Minimum funding requirements for qualified pension plans	\$ 35	\$ 23	\$ —
Employer contributions to the qualified pension plans	110	23	24
Employer contributions to the non-qualified pension plans	7	7	8

CenterPoint Energy expects to make contributions of approximately \$71 million and \$6 million to the qualified and non-qualified pension plans in 2026, respectively.

Changes in pension obligations and plan assets may not be immediately recognized as pension expense in CenterPoint Energy’s Statements of Consolidated Income, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension expense recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

As the sponsor of a plan, CenterPoint Energy is required to (a) recognize on its Consolidated Balance Sheet an asset for the plan’s over-funded status or a liability for the plan’s under-funded status, (b) measure a plan’s assets and obligations as of the end of the fiscal year and (c) recognize changes in the funded status of the plans in the year that changes occur through adjustments to other comprehensive income and, when related to its rate-regulated utilities with recoverability of cost, to regulatory assets.

The projected benefit obligation for all defined benefit pension plans was \$1.5 billion as of December 31, 2025 and 2024, respectively. The projected benefit obligation remained generally consistent from December 31, 2024 to December 31, 2025 as impacts resulting from the decrease in discount rates were offset by actual return on plan assets exceeding expected return on plan assets.

As of December 31, 2025, the projected benefit obligation exceeded the market value of plan assets of CenterPoint Energy’s pension plans by \$272 million. Changes in interest rates or the market values of the securities held by the plan during a year could materially, positively or negatively, change the funded status and affect the level of pension expense and required contributions at the next remeasurement.

Houston Electric and CERC participate in CenterPoint Energy's qualified and non-qualified pension plans covering substantially all employees. Pension cost by Registrant was as follows for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Pension cost	\$ 49	\$ 24	\$ 15	\$ 51	\$ 23	\$ 18	\$ 53	\$ 27	\$ 19

The calculation of pension cost and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2025, CenterPoint Energy's qualified pension plans had an expected long-term rate of return on plan assets of 7.00%, which is the same as the 7.00% rate assumed as of December 31, 2024. The expected rate of return assumption was developed using the targeted asset allocation of our plans and the expected return for each asset class. CenterPoint Energy regularly reviews its actual asset allocation and periodically rebalances plan assets to reduce volatility and better match plan assets and liabilities.

As of December 31, 2025, the projected benefit obligation was calculated assuming a discount rate of 5.35%, which is 25 basis points lower than the 5.60% discount rate assumed as of December 31, 2024 attributed primarily to rising interest rates. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of CenterPoint Energy's plans.

CenterPoint Energy's actuarially determined pension and other postemployment cost for 2025 and 2024 that is greater or less than the amounts being recovered through rates in the majority of Texas jurisdictions is deferred as a regulatory asset or liability, respectively. Pension cost for 2026, including the non-qualified benefit restoration plan, is estimated to be \$49 million before applicable regulatory deferrals and capitalization, based on an expected return on plan assets of 7.00% and a discount rate of 5.35% as of December 31, 2025. If the expected return assumption were lowered by 50 basis points from 7.00% to 6.50%, the 2026 pension cost would increase by approximately \$6 million.

As of December 31, 2025, the pension plans projected benefit obligation, including the unfunded non-qualified pension plans, exceeded plan assets by \$272 million. If the discount rate were lowered by 50 basis points from 5.35% to 4.85%, CenterPoint Energy's projected benefit obligation would increase by approximately \$62 million and its 2026 pension cost would decrease by approximately \$1 million. The expected reduction in pension cost due to the decrease in discount rate is a result of the expected correlation between the reduced interest rate and appreciation of fixed income assets in pension plans with significantly more fixed income instruments than equity instruments. In addition, the assumption change would impact CenterPoint Energy's Consolidated Balance Sheets by increasing the regulatory asset recorded as of December 31, 2025 by \$55 million and would result in an incremental charge to comprehensive income in 2025 of \$6 million, net of tax of \$1 million, due to the increase in the projected benefit obligation.

Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact CenterPoint Energy's future pension expense and liabilities. CenterPoint Energy cannot predict with certainty what these factors will be in the future.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Impact of Changes in Interest Rates, Equity Prices and Energy Commodity Prices

The Registrants are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in the Registrants' consolidated financial statements. Most of the revenues and income from the Registrants' business activities are affected by market risks. Categories of market risk include exposure to interest rates, equity prices and commodity prices through non-trading activities. A description of each market risk is set forth below:

- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates;
- Equity price risk results from exposures to changes in prices of individual equity securities (CenterPoint Energy); and

- Commodity price risk results from exposures to price volatilities of commodities, such as natural gas, NGLs and other energy commodities (CenterPoint Energy).

Management has established comprehensive risk management policies to monitor and manage these market risks.

Interest Rate Risk

As of December 31, 2025, the Registrants had outstanding long-term debt and lease obligations and CenterPoint Energy had obligations under its ZENS that subject them to the risk of loss associated with movements in market interest rates. The Registrants seek to manage interest rate exposure by monitoring the effects of changes in market interest rates and using a combination of fixed and variable rate debt. Additionally, interest rate swaps are used to mitigate interest rate exposure when deemed appropriate.

CenterPoint Energy's floating rate obligations aggregated \$1.5 billion as of December 31, 2025 and 2024, which consisted primarily of commercial paper outstanding and short-term borrowings at Houston Electric. If the floating interest rates were to increase by 100 basis points from the floating interest rates at December 31, 2025, CenterPoint Energy's combined interest expense would increase by approximately \$15 million annually. CenterPoint Energy has \$500 million of floating rate notes that mature in 2026.

Houston Electric's floating rate obligations were \$500 million as of December 31, 2025 and 2024, which mature in the first quarter of 2026. If the floating interest rates were to increase by 100 basis points from the floating interest rates at December 31, 2025, Houston Electric's combined interest expense would increase by approximately \$5 million annually.

CERC's floating rate obligations aggregated \$559 million and \$599 million as of December 31, 2025 and 2024, respectively, which consisted of commercial paper outstanding. If the floating interest rates were to increase by 100 basis points from December 31, 2025 rates, CERC's combined interest expense would increase by approximately \$6 million annually. CERC has no floating rate notes maturing in 2026.

As of December 31, 2025 and 2024, CenterPoint Energy had outstanding fixed-rate debt (excluding indexed debt securities) aggregating \$21.7 billion and \$19.7 billion, respectively, in principal amount and having a fair value of \$21.1 billion and \$18.4 billion, respectively. Because these instruments are fixed-rate, they do not expose CenterPoint Energy to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately \$800 million if interest rates were to decline by 10% from their levels as of December 31, 2025. CenterPoint Energy has \$517 million of fixed-rate senior notes, \$1 billion of fixed-rate convertible senior notes, \$300 million of fixed-rate Houston Electric general mortgage bonds and \$60 million of fixed-rate CERC senior notes maturing in 2026.

As of December 31, 2025 and 2024, Houston Electric had outstanding fixed-rate debt aggregating \$9.7 billion and \$8.4 billion, respectively, in principal amount and having a fair value of approximately \$8.9 billion and \$7.3 billion, respectively. Because these instruments are fixed-rate, they do not expose Houston Electric to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately \$400 million if interest rates were to decline by 10% from their levels as of December 31, 2025. Houston Electric has \$300 million of fixed-rate general mortgage bonds maturing in 2026.

As of December 31, 2025 and 2024, CERC had outstanding fixed-rate debt aggregating \$4.2 billion and \$4.6 billion, respectively, in principal amount and having a fair value of \$4.2 billion and \$4.5 billion, respectively. Because these instruments are fixed-rate, they do not expose CERC to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately \$120 million if interest rates were to decline by 10% from their levels at December 31, 2025. CERC has \$60 million fixed-rate senior notes maturing in 2026.

In general, such an increase in fair value previously described would impact earnings and cash flows only if the Registrants were to reacquire all or a portion of these instruments in the open market prior to their maturity. The ZENS obligation is bifurcated into a debt component and a derivative component. The debt component of less than \$1 million at December 31, 2025 was a fixed-rate obligation and, therefore, did not expose CenterPoint Energy to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by less than \$1 million if interest rates were to decline by 10% from levels at December 31, 2025. Changes in the fair value of the derivative component, a \$564 million recorded liability at December 31, 2025, are recorded in CenterPoint Energy's Statements of Consolidated Income and, therefore, it is exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2025 levels, the fair value of the

derivative component liability would decrease by less than \$1 million, which would be recorded as a gain on indexed debt securities in CenterPoint Energy's Statements of Consolidated Income.

Equity Market Value Risk (CenterPoint Energy)

CenterPoint Energy is exposed to equity market value risk through its ownership of 10.2 million shares of AT&T Common, 0.9 million shares of Charter Common and 2.5 million shares of WBD Common, which CenterPoint Energy holds to facilitate its ability to meet its obligations under the ZENS. See Note 10 to the consolidated financial statements for a discussion of CenterPoint Energy's ZENS obligation. Changes in the fair value of the ZENS-Related Securities held by CenterPoint Energy are expected to substantially offset changes in the fair value of the derivative component of the ZENS. A decrease of 10% from the December 31, 2025 aggregate market value of these shares would result in a net loss of less than \$1 million, which would be recorded on a gross basis as both a gain on indexed debt securities and as a loss on equity securities in CenterPoint Energy's Statements of Consolidated Income.

Commodity Price Risk From Non-Trading Activities (CenterPoint Energy and CERC)

CenterPoint Energy's regulated operations are exposed to commodity price risk during severe weather events, such as hurricanes, tornadoes and severe winter weather conditions. Severe weather events can increase commodity prices related to natural gas, coal and purchased power, which may increase our costs of providing service, and those costs may not be recoverable in rates. Recovery of cost increases driven by rising commodity prices during severe weather events could be resisted by our regulators and our regulators might attempt to deny or defer timely recovery of those costs.

However, CenterPoint Energy's and CERC's regulated operations in Indiana have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which, subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. CenterPoint Energy's and CERC's utility natural gas operations in Indiana have regulatory authority to lock in pricing for up to 50% of annual natural gas purchases using arrangements with an original term of up to 10 years. This authority has been utilized to secure fixed price natural gas using both physical purchases and financial derivatives.

Although CenterPoint Energy's and CERC's regulated operations are exposed to limited commodity price risk, natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs and recovery of unaccounted for natural gas and other natural gas-related expenses, also mitigate the effect natural gas costs may have on CenterPoint Energy's financial condition. In 2008, the PUCO approved an exit of the merchant function in CenterPoint Energy's and CERC's Ohio natural gas service territory, allowing Ohio customers to purchase substantially all natural gas directly from retail marketers rather than from CenterPoint Energy or CERC.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of CenterPoint Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by regulators and commissions in various jurisdictions (collectively, the "Commissions") that have jurisdiction with respect to the rates of electric and gas transmission and distribution companies in those jurisdictions. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the Commissions. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions

to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the Commissions to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 19, 2026

We have served as the Company's auditor since 1932.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions, except per share amounts)		
Revenues:			
Utility revenues	\$ 9,301	\$ 8,589	\$ 8,524
Non-utility revenues	56	54	172
Total	9,357	8,643	8,696
Expenses:			
Utility natural gas, fuel and purchased power	2,113	1,715	2,061
Non-utility cost of revenues, including natural gas	4	3	99
Operation and maintenance	3,024	2,949	2,850
Depreciation and amortization	1,530	1,439	1,401
Taxes other than income taxes	576	547	525
Total	7,247	6,653	6,936
Operating Income	2,110	1,990	1,760
Other Income (Expense):			
Loss on sale	(49)	—	(13)
Gain (loss) on equity securities	(51)	20	31
Gain (loss) on indexed debt securities	55	(14)	(27)
Interest expense and other finance charges	(882)	(818)	(684)
Interest expense on Securitization Bonds	(21)	(20)	(17)
Other income, net	85	56	37
Total	(863)	(776)	(673)
Income Before Income Taxes	1,247	1,214	1,087
Income tax expense	195	195	170
Net Income	1,052	1,019	917
Income allocated to preferred shareholders	—	—	50
Income Available to Common Shareholders	\$ 1,052	\$ 1,019	\$ 867
Basic Earnings Per Common Share	\$ 1.61	\$ 1.58	\$ 1.37
Diluted Earnings Per Common Share	\$ 1.60	\$ 1.58	\$ 1.37
Weighted Average Common Shares Outstanding, Basic	653	643	631
Weighted Average Common Shares Outstanding, Diluted	656	644	633

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Net income	\$ 1,052	\$ 1,019	\$ 917
Other comprehensive income (loss):			
Adjustment to pension and other postemployment plans (net of tax expense (benefit) of \$0, \$4 and \$(1), respectively)	(8)	15	(5)
Net deferred gain from cash flow hedges (net of tax of \$0, \$0 and \$0)	—	4	1
Reclassification of deferred (gain) loss from cash flow hedges realized in net income (net of tax of \$0, \$0 and \$0)	(1)	(1)	—
Total	(9)	18	(4)
Comprehensive income	1,043	1,037	\$ 913
Income allocated to preferred shareholders	—	—	50
Comprehensive income available to common shareholders	\$ 1,043	\$ 1,037	\$ 863

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2025	December 31, 2024
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents (\$34 and \$21 related to VIEs, respectively)	\$ 38	\$ 24
Investment in equity securities	510	561
Accounts receivable (\$6 and \$2 related to VIEs, respectively), less allowance for credit losses of \$25 and \$28, respectively	806	717
Accrued unbilled revenues (\$4 and \$2 related to VIEs, respectively), less allowance for credit losses of \$2 and \$2, respectively	600	521
Materials and supplies	517	541
Natural gas and coal inventory	215	173
Taxes receivable	36	121
Current assets held for sale	2,669	1,361
Regulatory assets	170	239
Prepaid expenses and other current assets (\$6 and \$2 related to VIEs, respectively)	140	123
Total current assets	5,701	4,381
Property, Plant and Equipment, Net:		
Property, plant and equipment	44,676	42,667
Less: accumulated depreciation and amortization	10,620	10,578
Property, plant and equipment, net	34,056	32,089
Other Assets:		
Goodwill	3,550	3,943
Regulatory assets (\$683 and \$313 related to VIEs, respectively)	3,005	3,108
Other non-current assets	222	247
Total other assets	6,777	7,298
Total Assets	\$ 46,534	\$ 43,768

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (continued)

	December 31, 2025	December 31, 2024
	(in millions, except par value and shares)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	\$ 500	\$ 500
Current portion of VIE Securitization Bonds long-term debt	41	13
Indexed debt, net	—	2
Current portion of other long-term debt	1,873	51
Indexed debt securities derivative	564	619
Accounts payable	1,300	1,320
Taxes accrued	344	329
Interest accrued (\$7 and \$2 related to VIEs, respectively)	313	274
Dividends accrued	150	143
Customer deposits (\$2 and \$0 related to VIEs, respectively)	89	93
Current liabilities held for sale	520	176
Other current liabilities (\$15 and \$0 related to VIEs, respectively)	566	525
Total current liabilities	6,260	4,045
Other Liabilities:		
Deferred income taxes, net	4,602	4,389
Benefit obligations	491	550
Regulatory liabilities	2,692	2,999
Other non-current liabilities	770	722
Total other liabilities	8,555	8,660
Long-term Debt, net:		
VIE Securitization Bonds, net	664	308
Other long-term debt, net	19,902	20,089
Total long-term debt, net	20,566	20,397
Commitments and Contingencies (Note 14)		
Shareholders' Equity:		
Common stock, \$0.01 par value, 1,000,000,000 shares authorized, 652,869,575 shares and 651,727,276 shares outstanding, respectively	6	6
Additional paid-in capital	9,130	9,105
Retained earnings	2,043	1,572
Accumulated other comprehensive loss	(26)	(17)
Total shareholders' equity	11,153	10,666
Total Liabilities and Shareholders' Equity	\$ 46,534	\$ 43,768

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Cash Flows from Operating Activities:			
Net income	\$ 1,052	\$ 1,019	\$ 917
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	1,530	1,439	1,401
Deferred income taxes	122	221	31
Loss on sale	49	—	13
Loss (gain) on equity securities	51	(20)	(31)
Loss (gain) on indexed debt securities	(55)	14	27
Pension and postretirement contributions	(130)	(30)	(32)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(253)	(84)	423
Inventory	(17)	42	167
Accounts payable	(15)	210	(302)
Other current assets	146	(118)	1,183
Other current liabilities	64	106	57
Other non-current assets	(131)	(642)	(62)
Other non-current liabilities	157	(32)	25
Other operating activities, net	(84)	14	60
Net cash provided by operating activities	<u>2,486</u>	<u>2,139</u>	<u>3,877</u>
Cash Flows from Investing Activities:			
Capital expenditures	(4,870)	(4,513)	(4,401)
Payment for asset acquisition	(357)	—	—
Proceeds from divestitures	1,219	—	144
Other investing activities, net	(8)	24	24
Net cash used in investing activities	<u>(4,016)</u>	<u>(4,489)</u>	<u>(4,233)</u>
Cash Flows from Financing Activities:			
Decrease in short-term borrowings, net	(3)	(4)	(10)
Payments of commercial paper, net	(2)	(539)	(1,055)
Proceeds from long-term debt and term loans, net	3,714	3,955	6,044
Payments of long-term debt and term loans, including make-whole premiums	(1,579)	(1,050)	(3,190)
Payment of debt issuance costs	(46)	(35)	(55)
Payment of dividends on Common Stock	(574)	(522)	(485)
Payment of dividends on Preferred Stock	—	—	(50)
Proceeds from issuance of Common Stock, net	—	494	—
Redemption of Series A Preferred Stock	—	—	(800)
Other financing activities, net	39	(28)	(25)
Net cash provided by financing activities	<u>1,549</u>	<u>2,271</u>	<u>374</u>
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	<u>19</u>	<u>(79)</u>	<u>18</u>
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	<u>30</u>	<u>109</u>	<u>91</u>
Cash, Cash Equivalents and Restricted Cash at End of Period	<u>\$ 49</u>	<u>\$ 30</u>	<u>\$ 109</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2025		2024		2023	
	Shares	Amount	Shares	Amount	Shares	Amount
(in millions of dollars and shares, except authorized shares and par value)						
Cumulative Preferred Stock, \$0.01 par value; authorized 20,000,000 shares						
Balance, beginning of year	—	\$ —	—	\$ —	1	\$ 790
Redemption of Series A Preferred Stock	—	—	—	—	(1)	(790)
Balance, end of year	—	—	—	—	—	—
Common Stock, \$0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	652	6	631	6	630	6
Issuances of Common Stock	—	—	19	—	—	—
Issuances related to benefit and investment plans	1	—	2	—	1	—
Balance, end of year	653	6	652	6	631	6
Additional Paid-in-Capital						
Balance, beginning of year		9,105		8,604		8,568
Issuances of Common Stock, net of issuance costs		—		494		—
Issuances related to benefit and investment plans		25		7		36
Balance, end of year		9,130		9,105		8,604
Retained Earnings						
Balance, beginning of year		1,572		1,092		709
Net income		1,052		1,019		917
Common Stock dividends declared (see Note 11)		(581)		(539)		(492)
Series A Preferred Stock dividends declared (see Note 11)		—		—		(42)
Balance, end of year		2,043		1,572		1,092
Accumulated Other Comprehensive Loss						
Balance, beginning of year		(17)		(35)		(31)
Other comprehensive income (loss)		(9)		18		(4)
Balance, end of year		(26)		(17)		(35)
Total Shareholders' Equity		<u>\$ 11,153</u>		<u>\$ 10,666</u>		<u>\$ 9,667</u>

See Combined Notes to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Member of CenterPoint Energy Houston Electric, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Houston Electric, LLC and subsidiaries (an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.) (the "Company") as of December 31, 2025 and 2024, the related statements of consolidated income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Texas ("PUCT"), which has jurisdiction with respect to the rates of electric transmission and distribution companies in Texas. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the PUCT. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The PUCT's regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the PUCT in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the PUCT will not approve: (1)

full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company, and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the PUCT, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the PUCT included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the PUCT, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the PUCT to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the PUCT's treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 19, 2026

We have served as the Company's auditor since 1932.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Revenues	\$ 4,084	\$ 3,939	\$ 3,677
Expenses:			
Operation and maintenance	1,913	1,927	1,673
Depreciation and amortization	807	762	748
Taxes other than income taxes	312	295	262
Total	3,032	2,984	2,683
Operating Income	1,052	955	994
Other Income (Expense):			
Interest expense and other finance charges	(369)	(311)	(259)
Interest expense on Securitization Bonds	(6)	(3)	(8)
Other income, net	48	43	34
Total	(327)	(271)	(233)
Income Before Income Taxes	725	684	761
Income tax expense	147	138	168
Net Income	\$ 578	\$ 546	\$ 593

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Net income	\$ 578	\$ 546	\$ 593
Other comprehensive loss:			
Adjustment to pension and other postretirement plans (net of tax of \$0, \$0 and \$0)	(1)	(1)	—
Total	(1)	(1)	—
Comprehensive income	<u>\$ 577</u>	<u>\$ 545</u>	<u>\$ 593</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS

	December 31, 2025	December 31, 2024
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents (\$25 and \$14 related to VIEs, respectively)	\$ 25	\$ 14
Accounts and notes receivable, net (\$5 and \$0 related to VIEs, respectively), less allowance for credit losses of \$2 and \$2, respectively	326	307
Accrued unbilled revenues (\$3 and \$0 related to VIEs, respectively)	169	137
Accounts and notes receivable—affiliated companies	4	371
Materials and supplies	357	392
Prepaid expenses and other current assets (\$4 and \$0 related to VIEs, respectively)	49	44
Total current assets	930	1,265
Property, Plant and Equipment, Net		
Property, plant and equipment	23,947	21,750
Less: accumulated depreciation and amortization	4,944	4,628
Property, plant and equipment, net	19,003	17,122
Other Assets:		
Regulatory assets (\$384 and \$0 related to VIEs, respectively)	1,612	1,284
Other non-current assets	33	41
Total other assets	1,645	1,325
Total Assets	\$ 21,578	\$ 19,712
LIABILITIES AND MEMBER'S EQUITY		
Current Liabilities:		
Short-term borrowings	\$ 500	\$ 500
Current portion of VIE Securitization Bonds long-term debt	27	—
Current portion of other long-term debt	300	—
Accounts payable	579	681
Accounts and notes payable—affiliated companies	151	119
Taxes accrued	265	189
Interest accrued (\$5 and \$0 related to VIEs, respectively)	133	108
Other current liabilities (\$17 and \$0 related to VIEs, respectively)	198	144
Total current liabilities	2,153	1,741
Other Liabilities:		
Deferred income taxes, net	1,609	1,502
Benefit obligations	38	32
Regulatory liabilities	850	861
Other non-current liabilities	144	95
Total other liabilities	2,641	2,490
Long-Term Debt, net:		
VIE Securitization Bonds, net	369	—
Other long-term debt, net	8,883	8,322
Total long-term debt, net	9,252	8,322
Commitments and Contingencies (Note 14)		
Member's Equity:		
Common stock	—	—
Additional paid-in capital	5,683	5,589
Retained earnings	1,851	1,571
Accumulated other comprehensive loss	(2)	(1)
Total member's equity	7,532	7,159
Total Liabilities and Member's Equity	\$ 21,578	\$ 19,712

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Cash Flows from Operating Activities:			
Net income	\$ 578	\$ 546	\$ 593
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	807	762	748
Deferred income taxes	81	61	160
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(51)	(10)	16
Accounts receivable/payable–affiliated companies	(23)	25	(1)
Inventory	35	17	62
Accounts payable	(152)	89	(60)
Other current assets	(1)	7	(48)
Other current liabilities	121	76	44
Other non-current assets	(217)	(587)	(87)
Other non-current liabilities	23	(29)	(14)
Other operating activities, net	(24)	3	(12)
Net cash provided by operating activities	<u>1,177</u>	<u>960</u>	<u>1,401</u>
Cash Flows from Investing Activities:			
Capital expenditures	(2,831)	(2,642)	(2,279)
Decrease (increase) in notes receivable–affiliated companies	368	(130)	(238)
Other investing activities, net	114	5	14
Net cash used in investing activities	<u>(2,349)</u>	<u>(2,767)</u>	<u>(2,503)</u>
Cash Flows from Financing Activities:			
Proceeds from long-term debt and term loan, net	1,499	1,397	1,398
Payments of long-term debt	(200)	(161)	(156)
Increase (decrease) in notes payable–affiliated companies	54	—	(642)
Payment of debt issuance costs	(18)	(8)	(13)
Dividend to parent	(298)	(339)	(367)
Contribution from parent	94	844	885
Other financing activities, net	56	(1)	(2)
Net cash provided by financing activities	<u>1,187</u>	<u>1,732</u>	<u>1,103</u>
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	<u>15</u>	<u>(75)</u>	<u>1</u>
Cash, Cash Equivalents and Restricted Cash at Beginning of the Period	<u>14</u>	<u>89</u>	<u>88</u>
Cash, Cash Equivalents and Restricted Cash at End of the Period	<u>\$ 29</u>	<u>\$ 14</u>	<u>\$ 89</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2025		2024		2023	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	\$ —	1,000	\$ —	1,000	\$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		5,589		4,745		3,860
Contribution from parent		94		844		885
Balance, end of year		5,683		5,589		4,745
Retained Earnings						
Balance, beginning of year		1,571		1,364		1,138
Net income		578		546		593
Dividend to parent		(298)		(339)		(367)
Balance, end of year		1,851		1,571		1,364
Accumulated Other Comprehensive Loss						
Balance, beginning of year		(1)		—		—
Other comprehensive loss		(1)		(1)		—
Balance, end of year		(2)		(1)		—
Total Member's Equity		<u>\$ 7,532</u>		<u>\$ 7,159</u>		<u>\$ 6,109</u>

See Combined Notes to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholder of CenterPoint Energy Resources Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.) (the "Company") as of December 31, 2025 and 2024, the related statements of consolidated income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by regulators and commissions in various jurisdictions (collectively, the "Commissions") that have jurisdiction with respect to the rates of gas transmission and distribution companies in those jurisdictions. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the Commissions. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the

Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the Commissions to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 19, 2026

We have served as the Company's auditor since 1997.

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Revenues:			
Utility revenues	\$ 4,296	\$ 3,878	\$ 4,107
Non-utility revenues	48	47	42
Total	<u>4,344</u>	<u>3,925</u>	<u>4,149</u>
Expenses:			
Utility natural gas	1,803	1,489	1,856
Non-utility cost of revenues, including natural gas	4	3	3
Operation and maintenance	895	848	904
Depreciation and amortization	541	522	493
Taxes other than income taxes	242	234	243
Total	<u>3,485</u>	<u>3,096</u>	<u>3,499</u>
Operating Income	<u>859</u>	<u>829</u>	<u>650</u>
Other Income (Expense):			
Gain on sale	46	—	—
Interest expense and other finance charges	(194)	(197)	(178)
Other income, net	25	12	14
Total	<u>(123)</u>	<u>(185)</u>	<u>(164)</u>
Income Before Income Taxes	<u>736</u>	<u>644</u>	<u>486</u>
Income tax expense (benefit)	97	104	(26)
Net Income	<u>\$ 639</u>	<u>\$ 540</u>	<u>\$ 512</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Net income	\$ 639	\$ 540	\$ 512
Other comprehensive income (loss):			
Adjustment to pension and other postretirement plans (net of tax benefit of \$1, \$0 and \$0)	(2)	1	—
Total	(2)	1	—
Comprehensive income	\$ 637	\$ 541	\$ 512

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS

	December 31, 2025	December 31, 2024
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ —	\$ 2
Accounts receivable, less allowance for credit losses of \$19 and \$24, respectively	391	349
Accrued unbilled revenue, less allowance for credit losses of \$2 and \$2, respectively	372	338
Accounts receivable—affiliated companies	6	6
Material and supplies	114	105
Natural gas inventory	165	137
Taxes receivable	—	46
Current assets held for sale	2,495	1,266
Regulatory assets	169	238
Prepaid expenses and other current assets	48	50
Total current assets	3,760	2,537
Property, Plant and Equipment, Net:		
Property, plant and equipment	14,540	15,552
Less: accumulated depreciation and amortization	3,820	4,146
Property, plant and equipment, net	10,720	11,406
Other Assets:		
Goodwill	1,242	1,461
Regulatory assets	479	903
Other non-current assets	63	118
Total other assets	1,784	2,482
Total Assets	\$ 16,264	\$ 16,425

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS - (continued)

	December 31, 2025	December 31, 2024
(in millions)		
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Current portion of long-term debt	\$ 60	\$ 10
Accounts payable	480	405
Accounts and notes payable—affiliated companies	394	101
Taxes accrued	165	150
Interest accrued	74	82
Customer deposits	76	81
Current liabilities held for sale	520	176
Other current liabilities	242	255
Total current liabilities	2,011	1,260
Other Liabilities:		
Deferred income taxes, net	1,426	1,370
Benefit obligations	62	63
Regulatory liabilities	1,616	1,887
Other non-current liabilities	317	403
Total other liabilities	3,421	3,723
Long-Term Debt, Net	4,657	5,174
Commitments and Contingencies (Note 14)		
Stockholder's Equity:		
Common stock	—	—
Additional paid-in capital	4,519	4,519
Retained earnings	1,641	1,732
Accumulated other comprehensive income	15	17
Total stockholder's equity	6,175	6,268
Total Liabilities and Stockholder's Equity	\$ 16,264	\$ 16,425

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Cash Flows from Operating Activities:			
Net income	\$ 639	\$ 540	\$ 512
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	541	522	493
Deferred income taxes	8	55	(41)
Gain on sale	(46)	—	—
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(162)	(73)	410
Accounts receivable/payable—affiliated companies	2	38	(81)
Inventory	(34)	6	101
Accounts payable	134	43	(250)
Other current assets	124	(26)	1,050
Other current liabilities	(8)	20	44
Other non-current assets	152	(122)	13
Other non-current liabilities	(53)	89	40
Other operating activities, net	(35)	(24)	21
Net cash provided by operating activities	<u>1,262</u>	<u>1,068</u>	<u>2,312</u>
Cash Flows from Investing Activities:			
Capital expenditures	(1,527)	(1,439)	(1,619)
Decrease (increase) in notes receivable—affiliated companies	—	1	(1)
Proceeds from divestitures	1,219	—	—
Other investing activities, net	(53)	19	(23)
Net cash provided by (used in) investing activities	<u>(361)</u>	<u>(1,419)</u>	<u>(1,643)</u>
Cash Flows from Financing Activities:			
Decrease in short-term borrowings, net	(3)	(4)	(10)
Proceeds from (payments of) commercial paper, net	(40)	115	(321)
Proceeds from long-term debt and term loans, net	—	399	2,006
Payments of long-term debt and term loans	(420)	—	(2,332)
Increase in notes payable-affiliated companies	291	—	—
Payments of debt issuance costs	—	(3)	(14)
Dividend to parent	(730)	(442)	(496)
Contribution from parent	—	290	500
Other financing activities, net	(1)	(3)	(1)
Net cash provided by (used in) financing activities	<u>(903)</u>	<u>352</u>	<u>(668)</u>
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	<u>(2)</u>	<u>1</u>	<u>1</u>
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	<u>2</u>	<u>1</u>	<u>—</u>
Cash, Cash Equivalents and Restricted Cash at End of Period	<u>\$ —</u>	<u>\$ 2</u>	<u>\$ 1</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2025		2024		2023	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	\$ —	1,000	\$ —	1,000	\$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		4,519		4,229		3,729
Contribution from parent		—		290		500
Balance, end of year		4,519		4,519		4,229
Retained Earnings						
Balance, beginning of year		1,732		1,634		1,618
Net income		639		540		512
Dividend to parent		(730)		(442)		(496)
Balance, end of year		1,641		1,732		1,634
Accumulated Other Comprehensive Income						
Balance, beginning of year		17		16		16
Other comprehensive income (loss)		(2)		1		—
Balance, end of year		15		17		16
Total Stockholder's Equity		<u>\$ 6,175</u>		<u>\$ 6,268</u>		<u>\$ 5,879</u>

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

General. This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. Information contained herein relating to any individual Registrant is filed by such Registrant solely on its own behalf. No Registrant makes any representation as to information relating exclusively to the other Registrants or the subsidiaries of CenterPoint Energy, Inc. other than itself or its subsidiaries.

Except as discussed in Note 12, no Registrant has an obligation in respect of any other Registrant's debt securities, and holders of such debt securities should not consider the financial resources or results of operations of any Registrant other than the obligor in making a decision with respect to such securities.

Basis of Presentation. Included in this combined Form 10-K are the consolidated financial statements of the Registrants. The Combined Notes to the Consolidated Financial Statements apply to all Registrants and specific references to Houston Electric and CERC herein also pertain to CenterPoint Energy, unless otherwise indicated. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Background. CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems.

As of December 31, 2025, CenterPoint Energy's indirect, wholly-owned operating subsidiaries included:

- Houston Electric, which provides electric transmission service to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston;
- CERC Corp., which (i) directly owns and operates natural gas distribution systems in Minnesota and Texas, (ii) indirectly, through Indiana Gas and CEOH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; and
- SIGECO, which provides energy delivery services to electric and natural gas customers located in and near Evansville in southwestern Indiana and owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market.

As of December 31, 2025, CenterPoint Energy's reportable segments were Electric, Natural Gas, and Corporate and Other. Houston Electric and CERC each consist of a single reportable segment. For a description of CenterPoint Energy's reportable segments, see Note 16.

On March 7, 2025, SIGECO acquired 100% of the equity interests in Posey Solar, which was constructing a 191 MW solar array in Posey County, Indiana, for approximately \$357 million. On March 31, 2025, CenterPoint Energy, through its subsidiary CERC Corp., completed the sale of its Louisiana and Mississippi natural gas LDC businesses for approximately \$1.2 billion. On October 20, 2025, CenterPoint Energy, through CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH for total consideration of approximately \$2.62 billion, subject to adjustment as set forth in the Ohio Securities Purchase Agreement. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4.

Principles of Consolidation. The accompanying consolidated financial statements are prepared in conformity with GAAP. The accounts of the Registrants and their wholly-owned and majority-owned and controlled subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation; however, intercompany profits have not been eliminated when such amounts are probable of recovery under the affiliates' rate regulation process.

As of December 31, 2025, CenterPoint Energy, Houston Electric and SIGECO had VIEs including Transition Bond Company IV, Restoration Bond Company II and the SIGECO Securitization Subsidiary, which are consolidated. The

consolidated VIEs are wholly-owned, bankruptcy-remote, special purpose entities that were formed solely for the purpose of securitizing transition property or system restoration property or facilitating the securitization financing of qualified costs. CenterPoint Energy, through SIGECO, has a controlling financial interest in the SIGECO Securitization Subsidiary and is its primary beneficiary. Houston Electric has a controlling financial interest in each of Transition Bond Company IV and Restoration Bond Company II and is the primary beneficiary of each. Creditors of CenterPoint Energy, Houston Electric and SIGECO have no recourse to any assets or revenues of Transition Bond Company IV and Restoration Bond Company II or the SIGECO Securitization Subsidiary, as applicable. The Securitization Bonds issued by these VIEs are payable only from and secured by transition property, system restoration property or securitization property, as applicable, and the bondholders have no recourse to the general credit of CenterPoint Energy, Houston Electric or SIGECO. For further information, see Note 7.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(b) Revenues

The Registrants record revenue for electricity delivery and natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Electricity deliveries not billed by month-end are accrued based on actual AMS meter data, supply volumes, estimated line loss and applicable tariff rates. Natural gas sales not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates. For further discussion, see Note 5.

(c) MISO Transactions

Indiana Electric is a member of the MISO. MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on at least a net hourly position, in which net purchases within that interval are recorded as Utility natural gas, fuel and purchased power and net sales within that interval are recorded as Utility revenues on CenterPoint Energy's Statements of Consolidated Income. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

(d) Environmental Costs

The Registrants (i) expense or capitalize environmental expenditures, as appropriate, depending on their future economic benefit; (ii) expense amounts that relate to an existing condition caused by past operations that do not have future economic benefit; and (iii) record undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(e) Cash and Cash Equivalents and Restricted Cash

For purposes of reporting cash flows, the Registrants consider cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase. Cash and cash equivalents held by the Bond Companies and the SIGECO Securitization Subsidiary solely to support servicing the Securitization Bonds as of December 31, 2025 and 2024 are reflected on CenterPoint Energy's and Houston Electric's Consolidated Balance Sheets.

In connection with the issuance of Securitization Bonds, CenterPoint Energy and Houston Electric were required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds and are not included in cash and cash equivalents. For more information on restricted cash, see Note 17.

(f) Accounts Receivable and Allowance for Credit Losses

Accounts receivable are recorded at the invoiced amount and do not bear interest. Management reviews historical write-offs, current available information and reasonable and supportable forecasts to estimate and establish allowance for credit losses. Account balances are charged off against the allowance when management determines it is probable that the receivable will not be recovered. See Note 7 for further information about regulatory deferrals of bad debt expense, including those related to the February 2021 Winter Storm Event.

(g) Inventory

The Registrants' inventory consists principally of materials and supplies, and for CERC, natural gas, and for CenterPoint Energy, coal inventory. Materials and supplies are valued at the lower of average cost or market, are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Inventory related to CenterPoint Energy's regulated operations is valued at historical cost consistent with ratemaking treatment. Coal inventory is valued at average cost. Certain natural gas in storage at CenterPoint Energy's and CERC's utilities are recorded using the last in, first out (LIFO) method. CenterPoint Energy's and CERC's balances in inventory that were valued using LIFO method were as follows for the periods presented:

	Year Ended December 31,			
	2025 (1)	2024	2025 (1)	2024
	CenterPoint Energy		CERC	
			(in millions)	
LIFO inventory	\$ 104	\$ 94	\$ 84	\$ 73

(1) Based on the average cost of gas purchased during December 2025, both CenterPoint Energy's and CERC's cost of replacing inventories carried at LIFO cost was \$16 million higher than the carrying value at December 31, 2025.

(h) Long-lived Assets

The Registrants record property, plant and equipment at historical cost and expense repair and maintenance costs as incurred.

The Registrants periodically evaluate long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. For rate-regulated businesses, recoverability of long-lived assets is assessed by determining if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. For businesses that are not rate-regulated, recoverability is assessed based on an estimate of undiscounted cash flows attributable to the assets compared to the carrying value of the assets. No long-lived asset impairments were recorded in 2025, 2024 or 2023.

The Registrants compute depreciation and amortization using the straight-line method based on economic lives or regulatory-mandated recovery periods. Amortization expense includes amortization of certain regulatory assets.

(i) Goodwill

CenterPoint Energy and CERC perform goodwill impairment tests at least annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. Goodwill is evaluated for impairment by performing a qualitative assessment or using a quantitative test. If CenterPoint Energy or CERC chooses to perform a qualitative assessment and determine it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the quantitative test is then performed; otherwise, no further testing is required. The quantitative test, if required, is performed by comparing the fair value of each reporting unit with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is primarily determined based on a weighted combination of income and market approaches. When the carrying amount is in excess of the estimated fair value of the reporting unit, the excess amount is recorded as an impairment charge, not to exceed the carrying amount of goodwill. CenterPoint Energy includes deferred tax assets and liabilities within its reporting unit's carrying value for the purposes of annual and interim impairment tests, regardless of whether the estimated fair value reflects the disposition of such assets and liabilities. For further information about the goodwill impairment tests, see Note 6.

(j) Regulatory Assets and Liabilities

The Registrants apply the guidance for accounting for regulated operations within the Electric reportable segment and the Natural Gas reportable segment. The Registrants' rate-regulated subsidiaries may collect revenues subject to refund pending final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgment of the ultimate outcomes of the proceedings.

The Registrants' rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. In addition, a portion of the amount of removal costs collected from customers that relate to AROs has been reflected as an asset retirement liability in accordance with accounting guidance for AROs.

The Registrants account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. When an ARO is recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Registrants recognize a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. The estimates of future liabilities are developed using a discounted cash flow model based upon estimates and assumptions of future costs, interest rates, credit-adjusted risk-free rates and the estimated timing of settlement.

For further detail on the Registrants' regulatory assets and liabilities, see Note 7.

(k) Capitalization and Deferral of Interest, including AFUDC

The Registrants capitalize interest and AFUDC as a component of projects under construction and amortize it over the assets' estimated useful lives once the assets are placed in service. Additionally, the Registrants defer interest costs into a regulatory asset when amounts are probable of recovery. Deferred debt interest is amortized over the recovery period for rate-making purposes. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. Although AFUDC increases both property, plant and equipment and earnings, it is realized in cash when the assets are included in rates. The table below includes interest capitalized or deferred for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Capitalized interest and AFUDC debt (1)	\$ 37	\$ 21	\$ 7	\$ 33	\$ 18	\$ 8	\$ 32	\$ 18	\$ 6
AFUDC equity (2)	74	37	15	66	33	17	62	32	14
Deferred debt interest (3)	71	39	30	65	24	36	65	16	43

- (1) Included in Interest expense and other finance charges on the Registrants' respective Statements of Consolidated Income.
- (2) Included in Other income (expense), net on the Registrants' respective Statements of Consolidated Income.
- (3) Represents the amount on certain regulatory assets that are authorized to earn a return, such as debt post in-service carrying costs on property, plant and equipment, gas costs, storm restoration costs, and TEEEF (including returns on both regulatory and lease assets) and is included in Interest expense and other finance charges on the Registrants' respective Statements of Consolidated Income.

(l) Leases

An arrangement is determined to be a lease at inception based on whether the Registrant has the right to control the use of an identified asset. ROU assets represent the Registrants' right to use the underlying asset for the lease term and lease liabilities represent the Registrants' obligation to make lease payments arising from the lease. ROU assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term, including payments at commencement that depend on an index or rate. Most leases in which the Registrants are the lessee do not have a readily determinable implicit rate, so an incremental borrowing rate, based on the information available at the lease commencement date, is utilized to determine the present value of lease payments. When a secured borrowing rate is not readily available, unsecured borrowing rates are adjusted for the effects of collateral to determine the incremental borrowing rate. Each Registrant uses the implicit rate for agreements in which it is a lessor. Lease income and expense for operating leases and ROU amortization for finance leases are recognized on a straight-line basis over the lease term.

The Registrants have lease agreements with lease and non-lease components and have elected the practical expedient to combine lease and non-lease components for certain classes of leases, such as office buildings and TEEEF. For classes of leases in which lease and non-lease components are not combined, consideration is allocated between components based on the stand-alone prices. Sublease income is not significant to the Registrants.

The Registrants' lease agreements do not contain any material residual value guarantees, material restrictions or material covenants. Except as described in Note 18, there are no lease transactions between related parties. Agreements in which the Registrants are lessors do not include provisions for the lessee to purchase the assets. Because risk is minimal, the Registrants do not take any significant actions to manage risk associated with the residual value of their leased assets.

The Registrants' operating lease agreements are primarily equipment and real property leases, including land and office facility leases. CenterPoint Energy and Houston Electric also have finance lease agreements for TEEEF. The Registrants' lease terms may include options to extend or terminate a lease when it is reasonably certain that those options will be exercised. The Registrants have elected an accounting policy that exempts leases with terms of one year or less from the recognition requirements of ASC 842. For further details on the Registrants' leases, see Note 19.

(m) Income Taxes

Houston Electric and CERC are included in CenterPoint Energy's U.S. federal consolidated income tax return. Houston Electric and CERC report their income tax provision on a separate entity basis pursuant to a tax sharing policy with CenterPoint Energy. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy.

The Registrants use the asset and liability method of accounting for deferred income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. A valuation allowance is established against deferred tax assets for which management believes realization is not considered to be more likely than not. The Registrants recognize interest and penalties as a component of income tax expense (benefit), as applicable, in their respective Statements of Consolidated Income.

To the extent certain EDIT of the Registrants' rate-regulated subsidiaries may be recoverable or payable through future rates, regulatory assets and liabilities have been recorded, respectively. See Note 13 for further discussion.

The Registrants use the portfolio approach to recognize income tax effects on other comprehensive income from accumulated other comprehensive income.

Investment tax credits are deferred and amortized to income over the approximate lives of the related property. Production tax credits extended by the IRA may be used to reduce current federal income taxes payable.

(n) Investments in Equity Securities (CenterPoint Energy)

CenterPoint Energy reports equity securities at estimated fair value in the Consolidated Balance Sheets, and any gains and losses, net of any transaction costs, are recorded as Gain (loss) on equity securities in the Statements of Consolidated Income. For further discussion on equity securities, see Note 10.

(o) Assets Held for Sale

Generally, a long-lived asset to be sold is classified as held for sale in the period in which management, with approval from the Board, as applicable, commits to a plan to sell, and a sale is expected to be completed within one year. The Registrants record assets and liabilities held for sale, or the disposal group, at the lower of their carrying value or their fair value less cost to sell. If a disposal group reflects a component of a reporting unit and meets the definition of a business, the goodwill within that reporting unit is allocated to the disposal group based on the relative fair value of the components representing a business that will be retained and disposed. Goodwill is not allocated to a portion of a reporting unit that does not meet the definition of a business.

Fair value is the amount at which an asset, liability or business could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value could be different if different estimates and assumptions in these valuation techniques were applied. Fair value measurements require significant judgment and often unobservable inputs, including (i) projected timing and amount of future cash flows, which factor in planned growth initiatives, (ii) the regulatory environment, as applicable, and (iii) discount rates reflecting risk inherent in the future market prices. Changes in these assumptions could have a significant impact on the resulting fair value.

As of December 31, 2025, certain assets and liabilities representing the Ohio natural gas LDC business met the held for sale criteria. The sale will be considered an asset sale for tax purposes, requiring net deferred tax liabilities to be excluded from held for sale balances. Although the Ohio natural gas LDC business met the held for sale criteria as of December 31, 2025, and the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria as of December 31, 2024, their disposals did not represent a strategic shift for CenterPoint Energy or CERC, as both retain significant operations in, and continue to invest in, their natural gas businesses. Therefore, the assets and liabilities, as well as the related income and expenses, associated with this transaction were not reflected as discontinued operations on CenterPoint Energy's and CERC's Consolidated Balance Sheets and Statements of Consolidated Income, as applicable, and the December 31, 2024 Consolidated Balance Sheets were not required to be recast for assets held for sale. For further discussion of the sale, see Note 4.

(p) Recent Accounting Pronouncements

In September 2025, the FASB issued ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software (“ASU 2025-06”). This ASU modernizes the accounting for software costs to adapt to an incremental and iterative software development method. ASU 2025-06 is effective for annual periods beginning after December 15, 2027, and may be applied using a prospective, modified prospective or retrospective transition approach. The Registrants are currently evaluating the impact of this ASU on their respective consolidated financial statements.

In November 2024, the FASB issued ASU 2024-03, Income Statement—Reporting Comprehensive Income (Topic 220): Expense Disaggregation Disclosures (“ASU 2024-03”). This ASU improves disclosure of a public business entity's expense by requiring disaggregated disclosure of expenses in commonly presented expense captions. ASU 2024-03 is effective for annual periods beginning after December 15, 2026, and for interim periods beginning after December 15, 2027. Early adoption is permitted. The Registrants are currently evaluating the impact of this ASU on their respective consolidated financial statements.

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures (“ASU 2023-09”). This ASU enhances the transparency of income tax disclosures related to rate reconciliation and income taxes. ASU 2023-09 is effective for annual periods beginning after December 15, 2024. The Registrants adopted this ASU on December 31, 2025, on a retrospective basis. The adoption of this ASU did not have a material impact on their respective consolidated financial statements. See Note 13 for additional disclosures related to effective tax rate reconciliation and Note 17 for additional disclosures related to income taxes paid.

Management believes that all other recently adopted and recently issued accounting standards that are not yet effective will not have a material impact on the Registrants' financial position, results of operations or cash flows upon adoption.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following for the periods presented:

	Weighted Average Useful Lives (in years)	December 31, 2025			December 31, 2024		
		Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net	Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net
		(in millions)					
CenterPoint Energy							
Electric transmission and distribution	36	\$ 23,721	\$ 5,102	\$ 18,619	\$ 21,387	\$ 4,810	\$ 16,577
Electric generation	35	1,569	169	1,400	1,107	154	953
Natural gas distribution	33	15,430	3,995	11,435	16,399	4,326	12,073
Finance ROU asset (1)	7.5	662	327	335	662	232	430
Other property	21	3,294	1,027	2,267	3,112	1,056	2,056
Total		\$ 44,676	\$ 10,620	\$ 34,056	\$ 42,667	\$ 10,578	\$ 32,089
Houston Electric							
Electric transmission and distribution	36	\$ 20,726	\$ 3,915	\$ 16,811	\$ 18,645	\$ 3,647	\$ 14,998
Finance ROU asset (1)	7.5	662	327	335	662	232	430
Other property	20	2,559	702	1,857	2,443	749	1,694
Total		\$ 23,947	\$ 4,944	\$ 19,003	\$ 21,750	\$ 4,628	\$ 17,122
CERC							
Natural gas distribution	33	\$ 14,451	\$ 3,792	\$ 10,659	\$ 15,474	\$ 4,118	\$ 11,356
Other property	10	89	28	61	78	28	50
Total		\$ 14,540	\$ 3,820	\$ 10,720	\$ 15,552	\$ 4,146	\$ 11,406

(1) Houston Electric recognized a finance ROU asset as of December 31, 2025 and December 31, 2024 related to TEEEF. See Note 19 for further discussion.

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
(in millions)									
Depreciation	\$ 1,256	\$ 588	\$ 502	\$ 1,177	\$ 545	\$ 492	\$ 1,092	\$ 484	\$ 459
Amortization of securitized regulatory assets	26	12	—	90	74	—	163	155	—
Other amortization	248	207	39	172	143	30	146	109	34
Total	\$ 1,530	\$ 807	\$ 541	\$ 1,439	\$ 762	\$ 522	\$ 1,401	\$ 748	\$ 493

(c) AROs

The Registrants have recorded AROs associated with the removal of asbestos and asbestos-containing material in their buildings, including substation building structures. CenterPoint Energy recorded AROs relating to the closure of the ash ponds at A.B. Brown and F.B. Culley as well as certain sites in Indiana pursuant to the CCR Legacy Rule; see Note 14(c) for further discussion. CenterPoint Energy and Houston Electric also recorded AROs relating to treated wood poles for electric distribution, distribution transformers containing PCB (also known as Polychlorinated Biphenyl), and underground fuel storage tanks. CenterPoint Energy and CERC also recorded AROs relating to gas pipelines abandoned in place.

A reconciliation of the changes in the ARO liability recorded in Other non-current liabilities on each of the Registrants' respective Consolidated Balance Sheets is as follows for the periods presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Beginning balance	\$ 588	\$ 39	\$ 363	\$ 590	\$ 40	\$ 380
Additions	8	—	4	11	—	—
Accretion expense (1)	27	2	14	21	1	16
Revisions in estimates (2)	(19)	(3)	(60)	(34)	(2)	(33)
Impact of divestiture of Louisiana and Mississippi natural gas LDCs (3)	(60)	—	(60)	—	—	—
Ending balance (4)	<u>\$ 544</u>	<u>\$ 38</u>	<u>\$ 261</u>	<u>\$ 588</u>	<u>\$ 39</u>	<u>\$ 363</u>

- (1) Reflected in Regulatory assets on each of the Registrants' respective Consolidated Balance Sheets.
- (2) In 2025 and 2024, CenterPoint Energy, Houston Electric and CERC reflected a decrease in their respective ARO liability, which was primarily attributable to increases in the long-term interest rates used for discounting in the ARO calculation.
- (3) Reflected a decrease in ARO liability related to the divestiture of the Louisiana and Mississippi natural gas LDCs on March 31, 2025. See Note 4 for further information regarding the divestiture.
- (4) Includes \$34 million related to the Ohio natural gas LDC business, which was classified as held for sale as of December 31, 2025 in CenterPoint Energy's and CERC's Consolidated Balance Sheets. See Note 4 for further information regarding the divestiture.

(4) Held for Sale, Divestitures and Acquisition (CenterPoint Energy and CERC)

Held for Sale. On October 20, 2025, CERC Corp. entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH to NFGC. The purchase price is \$2.62 billion, which is comprised of the following: (i) \$1.42 billion in cash payable to CERC Corp. upon closing of the transaction, subject to adjustments as set forth in the Ohio Securities Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing of the transaction; and (ii) a 364-day seller promissory note, in the original principal amount of \$1.2 billion, to be issued by NFGC at the closing of the transaction and payable to CERC Corp. as provided by the terms and conditions of the Seller Note Agreement. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions, including (i) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; (ii) completion of a notice filing and review with the PUCO; and (iii) customary conditions regarding the accuracy of the representations and warranties and compliance by the parties with their respective obligations under the Ohio Securities Purchase Agreement. The transaction is not subject to a financing condition and will not close prior to October 1, 2026 without the consent of CERC Corp. As of December 31, 2025, the assets included approximately 6,000 miles of transmission and distribution pipeline in Ohio serving approximately 337,000 metered customers. The Ohio natural gas LDC business is reflected in CenterPoint Energy's Natural Gas reportable segment and CERC's single reportable segment. A filing was made on January 9, 2026, notifying the PUCO of the execution of the Ohio Securities Purchase Agreement.

In October 2025, certain assets and liabilities representing the Ohio natural gas LDC business met the held for sale criteria. Neither CenterPoint Energy nor CERC recognized any gains or losses upon classification of held for sale during the year ended December 31, 2025. See Note 6 for further disclosure regarding the amount of goodwill allocated to the businesses to be sold.

The assets and liabilities of the Ohio natural gas LDC business classified as held for sale in CenterPoint Energy's and CERC's Consolidated Balance Sheets, as applicable, included the following:

	December 31, 2025	
	CenterPoint Energy	CERC
	(in millions)	
Accounts receivable, net	\$ 47	\$ 47
Accrued unbilled revenues	45	45
Materials and supplies	9	9
Property, plant and equipment, net	1,803	1,803
Goodwill	393	219
Regulatory assets	372	372
Total current assets held for sale	<u>\$ 2,669</u>	<u>\$ 2,495</u>
Accounts payable	\$ 100	\$ 100
Taxes accrued	37	37
Customer deposits	5	5
Other current liabilities	8	8
Regulatory liabilities	328	328
Other non-current liabilities	42	42
Total current liabilities held for sale	<u>\$ 520</u>	<u>\$ 520</u>

Although the Ohio natural gas LDC business meets the held for sale criteria, its proposed disposal does not represent a strategic shift for CenterPoint Energy and CERC as both will retain significant operations in, and will continue to invest in, their natural gas businesses. Therefore, the assets and liabilities, as well as the related income and expenses, associated with this transaction were not reflected as discontinued operations on CenterPoint Energy's and CERC's Consolidated Balance Sheets and Statements of Consolidated Income, as applicable, and the December 31, 2024 Consolidated Balance Sheets were not required to be recast for assets held for sale. Since the depreciation on the assets of the Ohio natural gas LDC business will continue to be reflected in revenues through customer rates until the expected closing of the transaction and will be reflected in the carryover basis of the rate-regulated assets once sold, CenterPoint Energy and CERC will continue to record depreciation on those assets through the expected closing of the transaction.

The pre-tax income for the Ohio natural gas LDC business, excluding corporate allocations, included in CenterPoint Energy's and CERC's Statements of Consolidated Income is as follows:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Income Before Income Taxes	\$ 98	\$ 95	\$ 96

Divestiture of Louisiana and Mississippi natural gas LDC businesses. On February 19, 2024, CERC Corp. entered into the LAMS Asset Purchase Agreement, pursuant to which CERC Corp. agreed to sell its Louisiana and Mississippi natural gas LDC businesses. The purchase price for the Louisiana and Mississippi natural gas LDC businesses was \$1.2 billion. The transaction closed on March 31, 2025. As of the closing date, the businesses included approximately 12,000 miles of main pipeline in Louisiana and Mississippi serving more than 380,000 customers. Prior to the sale, the Louisiana and Mississippi natural gas LDC businesses were reflected in CenterPoint Energy's Natural Gas reportable segment and CERC's single reportable segment, as applicable.

The sale was considered an asset sale for tax purposes, requiring net deferred tax liabilities to be excluded from held for sale balances. The deferred taxes associated with the businesses were recognized as a deferred income tax benefit by CenterPoint Energy and CERC upon closing of the sale in 2025.

Although the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria at December 31, 2024, their disposals did not represent a strategic shift for CenterPoint Energy or CERC, as both retain significant operations in, and continue to invest in, their natural gas businesses. Therefore, the assets and liabilities, as well as the related income and

expenses, associated with these transactions were not reflected as discontinued operations on CenterPoint Energy's and CERC's Consolidated Balance Sheets and Statements of Consolidated Income, as applicable. Since the depreciation on the Louisiana and Mississippi natural gas LDC businesses' assets continued to be reflected in revenues through customer rates until the closing of the transaction and was then reflected in the carryover basis of the rate-regulated assets after the sale, CenterPoint Energy and CERC continued to record depreciation on those assets through the closing of the transaction. The Registrants recorded assets and liabilities held for sale at the lower of their carrying value or their estimated fair value less cost to sell.

CenterPoint Energy and CERC recognized a loss of \$49 million and a gain of \$46 million, respectively, net of transaction costs of \$21 million, in connection with the closing of the disposition of the Louisiana and Mississippi natural gas LDC businesses during the year ended December 31, 2025. Goodwill of \$217 million and \$122 million was allocated to the Louisiana and Mississippi natural gas LDC businesses by CenterPoint Energy and CERC, respectively, at the time the held for sale criteria was met and such amount was subsequently derecognized following the completion of the sale on March 31, 2025. As of December 31, 2025, CenterPoint Energy and CERC had a receivable of \$6 million for working capital and other customary adjustments set forth in the LAMS Asset Purchase Agreement, which was received from the LAMS Buyers in the first quarter of 2026.

The assets and liabilities of the Louisiana and Mississippi natural gas LDC businesses classified as held for sale in CenterPoint Energy's and CERC's Consolidated Balance Sheets, as applicable, included the following:

	December 31, 2024	
	CenterPoint Energy	CERC
	(in millions)	
Accounts receivable, net	\$ 27	\$ 27
Accrued unbilled revenues	26	26
Materials and supplies	13	13
Natural gas inventory	5	5
Property, plant and equipment, net	1,052	1,052
Goodwill	217	122
Regulatory assets	15	15
Other	6	6
Total current assets held for sale	\$ 1,361	\$ 1,266
Short-term borrowings	\$ 3	\$ 3
Accounts payable	44	44
Customer deposits	14	14
Regulatory liabilities	31	31
Other	84	84
Total current liabilities held for sale	\$ 176	\$ 176

The pre-tax income for the Louisiana and Mississippi natural gas LDC businesses, excluding interest and corporate allocations, included in CenterPoint Energy's and CERC's Statements of Consolidated Income is as follows for the periods presented:

	Year Ended December 31,		
	2025 (1)	2024	2023
	(in millions)		
Income Before Income Taxes	\$ 48	\$ 67	\$ 44

(1) Reflects pre-tax income, excluding interest and corporate allocations through March 31, 2025.

Effective on the date of the closing of the disposition of the Louisiana and Mississippi natural gas LDC businesses, CERC entered into the Transition Services Agreement, whereby CERC agreed to provide certain transition services, including accounting, customer operations, procurement, and technology functions, for a term of up to 24 months. Subject to the conditions in the Transition Services Agreement, the LAMS Buyers may terminate these support services with 60 days prior written notice. CenterPoint Energy's and CERC's charges to the LAMS Buyers for reimbursement of transition services and one-time setup costs totaled \$34 million during the year ended December 31, 2025. CenterPoint Energy's and CERC's Consolidated Balance Sheets included a receivable due from the LAMS Buyers for transition services of \$9 million as of

December 31, 2025.

Divestiture of Energy Systems Group. On May 21, 2023, CenterPoint Energy, through its subsidiary Vectren Energy Services, entered into an Equity Purchase Agreement to sell all of the outstanding limited liability company interests of Energy Systems Group to ESG Holdings Group, for a purchase price of \$157 million, subject to customary adjustments set forth in the Equity Purchase Agreement, including adjustments based on Energy Systems Group's net working capital at closing, indebtedness, cash and cash equivalents and transaction expenses. The transaction closed on June 30, 2023, and CenterPoint Energy received \$154 million in cash. In November 2024, CenterPoint Energy paid \$2 million to ESG Holdings Group for working capital and other adjustments set forth in the Equity Purchase Agreement. For a discussion of CenterPoint Energy's pre-disposition guarantees related to Energy Systems Group, see Note 14(b).

CenterPoint Energy recognized a loss on sale of approximately \$13 million, including \$3 million of transaction costs, during the year ended December 31, 2023, in connection with the closing of the sale of Energy Systems Group. Additionally, CenterPoint Energy recognized a current tax expense of \$32 million during the year ended December 31, 2023, as a result of the cash taxes payable upon the closing of the sale.

For the year ended December 31, 2023, the pre-tax loss for Energy Systems Group, excluding interest and corporate allocations, included in CenterPoint Energy's Statements of Consolidated Income was \$4 million, which reflected January 1, 2023 to June 30, 2023 results.

Acquisition of Posey Solar. On March 7, 2025, SIGECO acquired 100% of the equity interests in Posey Solar, which was constructing a 191 MW solar array in Posey County, Indiana, for approximately \$357 million. The purchase represents an asset acquisition. The lease obligations related to Posey Solar were approximately \$35 million at the time of acquisition. The purchase was subject to terms and conditions in an order approved by the IURC on September 6, 2023, allowing Indiana Electric to recover project costs, net of PTCs, in rate base rather than a levelized rate, through base rates or the CECA mechanism, depending on which provides more timely recovery. Posey Solar was placed into service on May 30, 2025. Indiana Electric began recovering on the asset through updated base rates on June 17, 2025. On February 3, 2025, the IURC approved Indiana Electric's request to convey PTCs to customers through the new tax adjustment rider.

(5) Revenue

In accordance with ASC 606, Revenue from Contracts with Customers, revenue is recognized when a customer obtains control of promised goods or services. The amount of revenue recognized reflects the consideration to which the Registrants expect to be entitled to receive in exchange for these goods or services.

ARPs are contracts between the utility and its regulators, not between the utility and a customer. The Registrants recognize ARP revenue as other revenues when the regulator-specified conditions for recognition have been met. Upon recovery of ARP revenue through incorporation in rates charged for utility service to customers, ARP revenue is reversed and recorded as revenue from contracts with customers. The recognition of ARP revenues and the reversal of ARP revenues upon recovery through rates charged for utility service may not occur in the same period.

The following tables disaggregate revenues by reportable segment and major source for the periods presented:

CenterPoint Energy

	Year Ended December 31, 2025			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	\$ 4,829	\$ 4,503	\$ 5	\$ 9,337
Other (1)	37	(17)	3	23
Eliminations	—	(3)	—	(3)
Total revenues	<u>\$ 4,866</u>	<u>\$ 4,483</u>	<u>\$ 8</u>	<u>\$ 9,357</u>

	Year Ended December 31, 2024			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	\$ 4,558	\$ 3,990	\$ 4	\$ 8,552
Other (1)	32	58	3	93
Eliminations	—	(2)	—	(2)
Total revenues	<u>\$ 4,590</u>	<u>\$ 4,046</u>	<u>\$ 7</u>	<u>\$ 8,643</u>

	Year Ended December 31, 2023			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	\$ 4,275	\$ 4,210	\$ 127	\$ 8,612
Other (1)	15	69	3	87
Eliminations	—	(3)	—	(3)
Total revenues	<u>\$ 4,290</u>	<u>\$ 4,276</u>	<u>\$ 130</u>	<u>\$ 8,696</u>

(1) Primarily consists of income from ARPs and leases.

Houston Electric

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Revenue from contracts with customers	\$ 4,054	\$ 3,930	\$ 3,684
Other (1)	30	9	(7)
Total revenues	<u>\$ 4,084</u>	<u>\$ 3,939</u>	<u>\$ 3,677</u>

(1) Primarily consists of income from ARPs and leases.

CERC

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Revenue from contracts with customers	\$ 4,362	\$ 3,868	\$ 4,083
Other (1)	(18)	57	66
Total revenues	<u>\$ 4,344</u>	<u>\$ 3,925</u>	<u>\$ 4,149</u>

(1) Primarily consists of income from ARPs and leases.

Revenues from Contracts with Customers

Electric (CenterPoint Energy and Houston Electric). Houston Electric distributes electricity to customers over time and customers consume the electricity when delivered. Indiana Electric generates, distributes and transmits electricity to customers over time and customers consume the electricity when delivered. Revenue, consisting of both volumetric and fixed tariff rates set by state regulators, such as the PUCT and the IURC, is recognized as electricity is delivered and represents amounts both billed and unbilled. Discretionary services requested by customers are provided at a point in time with control transferring upon the completion of the service. Revenue for discretionary services provided by Houston Electric is recognized upon completion of service based on the tariff rates set by the PUCT. Payments for electricity distribution and discretionary services are aggregated and received on a monthly basis. Houston Electric performs transmission services over time as a stand-ready obligation to provide a reliable network of transmission systems. Revenue is recognized upon time elapsed and the monthly tariff rate set by the regulator. Payments are received on a monthly basis. Indiana Electric customers are billed monthly and payment terms, set by the regulator, require payment within a month of billing.

Natural Gas (CenterPoint Energy and CERC). CenterPoint Energy and CERC distribute and transport natural gas to customers over time and customers consume the natural gas when delivered. Revenue, consisting of both volumetric and fixed tariff rates set by the state governing agency for that service area, is recognized as natural gas is delivered and represents amounts both billed and unbilled. Discretionary services requested by the customer are provided at a point in time with control transferring upon completion of the service. Revenue for discretionary services is recognized upon completion of service based on the tariff rates set by the applicable state regulator. Payments of natural gas distribution, transportation and discretionary services are aggregated and received on a monthly basis.

Contract Balances. When the timing of delivery of service is different from the timing of the payments made by customers and when the right to consideration is conditioned on something other than the passage of time, the Registrants recognize a contract liability when customer payment precedes performance. Those customers that prepay are represented by contract liabilities until the performance obligations are satisfied. The Registrants' contract liabilities are included in Accounts payable and Other current liabilities in their Consolidated Balance Sheets.

The opening and closing balances of accounts receivable and accrued unbilled revenues from contracts with customers are as follows:

CenterPoint Energy

	<u>Accounts Receivable (1) (2)</u>	<u>Accrued Unbilled Revenues (2)</u>
	(in millions)	
Opening balance as of December 31, 2024	\$ 666	\$ 521
Closing balance as of December 31, 2025	722	600
Increase	<u>\$ 56</u>	<u>\$ 79</u>

(1) Excludes balances related to customer or vendor cost reimbursements and insurance that are not attributable to revenues from contracts with customers.

(2) The opening balance as of December 31, 2024 also excluded receivables associated with the sale of CERC Corp.'s Louisiana and Mississippi natural gas LDC businesses. The closing balance as of December 31, 2025 also excluded receivables classified as held for sale associated with the Ohio natural gas LDC business.

Houston Electric

	<u>Accounts Receivable (1)</u>	<u>Accrued Unbilled Revenues</u>
	(in millions)	
Opening balance as of December 31, 2024	\$ 284	\$ 137
Closing balance as of December 31, 2025	300	169
Increase	<u>\$ 16</u>	<u>\$ 32</u>

(1) Excludes balances related to customer or vendor cost reimbursements and insurance that are not attributable to revenues from contracts with customers.

CERC

	<u>Accounts Receivable (1) (2)</u>	<u>Accrued Unbilled Revenues (2)</u>
	(in millions)	
Opening balance as of December 31, 2024	\$ 326	\$ 338
Closing balance as of December 31, 2025	357	372
Increase (decrease)	<u>\$ 31</u>	<u>\$ 34</u>

- (1) Excludes balances related to customer or vendor cost reimbursements and insurance that are not attributable to revenues from contracts with customers.
(2) The opening balance as of December 31, 2024 also excluded receivables associated with the sale of CERC Corp.'s Louisiana and Mississippi natural gas LDC businesses. The closing balance as of December 31, 2025 also excluded receivables classified as held for sale associated with the Ohio natural gas LDC business.

Practical Expedients and Exemption. Sales taxes and other similar taxes collected from customers are excluded from the transaction price. For contracts for which revenue from the satisfaction of the performance obligations is recognized in the amount invoiced, the practical expedient was elected and revenue expected to be recognized on these contracts has not been disclosed.

Allowance for Credit Losses and Bad Debt Expense

CenterPoint Energy and CERC segregate financial assets that fall under the scope of ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, primarily trade receivables due in one year or less, into portfolio segments based on shared risk characteristics, such as geographical location and regulatory environment, for evaluation of expected credit losses. Historical and current information, such as average write-offs, are applied to each portfolio segment to estimate the allowance for losses on uncollectible receivables. Additionally, the allowance for losses on uncollectible receivables is adjusted for reasonable and supportable forecasts of future economic conditions, which can include changing weather, commodity prices, regulations and macroeconomic factors, among others. Houston Electric had no material changes in its methodology to recognize losses on financial assets that fall under the scope of Topic 326, primarily due to the nature of its customers and regulatory environment. For a discussion of regulatory deferrals, see Note 7.

The table below summarizes the Registrants' bad debt expense amounts for the periods presented, net of regulatory deferrals:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Bad debt expense	\$ 19	\$ 1	\$ 14	\$ 21	\$ 1	\$ 16	\$ 18	\$ —	\$ 16

(6) Goodwill (CenterPoint Energy and CERC)

CenterPoint Energy's goodwill by reportable segment is as follows for the periods presented:

	Electric (1)	Natural Gas	Corporate and Other	Total
	(in millions)			
Balance at December 31, 2023	\$ 936	\$ 2,920	\$ 304	\$ 4,160
Held for Sale (2)	—	217	—	217
Balance at December 31, 2024	936	2,703	304	3,943
Held for Sale (3)	—	393	—	393
Balance at December 31, 2025	<u>\$ 936</u>	<u>\$ 2,310</u>	<u>\$ 304</u>	<u>\$ 3,550</u>

- (1) Balances are presented net of the accumulated goodwill impairment charge of \$185 million recorded in 2020.
- (2) Represents goodwill attributable to the Louisiana and Mississippi natural gas LDC businesses classified as held for sale as of December 31, 2024 and subsequently derecognized following completion of the sale on March 31, 2025. CenterPoint Energy did not recognize any goodwill impairments within the Natural Gas reportable segment for the year ended December 31, 2024. For further information, see Note 4.
- (3) Represents goodwill attributable to the Ohio natural gas LDC business classified as held for sale as of December 31, 2025. CenterPoint Energy did not recognize any goodwill impairments within the Natural Gas reportable segment for the year ended December 31, 2025. For further information, see Note 4.

CERC's goodwill is as follows for the periods presented:

	Total
	(in millions)
Balance at December 31, 2023	\$ 1,583
Held for Sale (1)	122
Balance at December 31, 2024	1,461
Held for Sale (2)	219
Balance at December 31, 2025	<u>\$ 1,242</u>

- (1) Represents goodwill attributable to the Louisiana and Mississippi natural gas LDC businesses classified as held for sale as of December 31, 2024 and subsequently derecognized following the completion of the sale on March 31, 2025. CERC did not recognize any goodwill impairments for the year ended December 31, 2024. For further information, see Note 4.
- (2) Represents goodwill attributable to the Ohio natural gas LDC business classified as held for sale as of December 31, 2025. CERC did not recognize any goodwill impairments during the year ended December 31, 2025. For further information, see Note 4.

CenterPoint Energy and CERC performed their annual goodwill impairment tests in the third quarter of each of 2025 and 2024 and determined that no goodwill impairment charge was required for any reporting unit as a result of those tests.

(7) Regulatory Matters

The following is a list of regulatory assets and liabilities reflected on the Registrants' respective Consolidated Balance Sheets for the periods presented:

	December 31, 2025		
	CenterPoint Energy	Houston Electric	CERC
	(in millions)		
Regulatory Assets:			
Future amounts recoverable from ratepayers related to:			
Benefit obligations (1)	\$ 372	\$ —	\$ 4
Asset retirement obligations & other	256	80	126
Net deferred income taxes	194	55	103
Total future amounts recoverable from ratepayers	822	135	233
Amounts deferred for future recovery related to:			
Cost recovery riders	57	—	62
Hurricanes and February 2021 Winter Storm Event Restoration Costs	18	18	—
May 2024 Storm Events	6	6	—
Hurricane Beryl	527	527	—
Hurricane Francine	25	25	—
Winter Storm Enzo	39	39	—
Other regulatory assets	191	110	80
Decoupling	8	—	8
TEEEF	83	83	—
Unrecognized equity return (2)	(120)	(93)	(24)
Total amounts deferred for future recovery	834	715	126
Amounts currently recovered in customer rates related to:			
Authorized trackers and cost deferrals	406	77	128
Securitized regulatory assets	695	384	—
Unamortized loss on reacquired debt and hedging	53	26	10
Gas recovery costs	71	—	70
Decoupling	20	—	20
Extraordinary gas costs	70	—	70
Regulatory assets related to TCJA	66	40	26
Hurricanes and February 2021 Winter Storm Event restoration costs	132	114	19
Other regulatory assets	33	—	33
Benefit obligations	2	2	—
TEEEF	161	161	—
Unrecognized equity return (2)	(190)	(42)	(87)
Total amounts recovered in customer rates (3)	1,519	762	289
Total Regulatory Assets	\$ 3,175	\$ 1,612	\$ 648
Total Current Regulatory Assets	\$ 170	\$ —	\$ 169
Total Non-Current Regulatory Assets	\$ 3,005	\$ 1,612	\$ 479
Regulatory Liabilities:			
Regulatory liabilities related to TCJA	\$ 1,233	\$ 646	\$ 428
Estimated removal costs	1,047	—	1,004
Other regulatory liabilities	456	219	214
Total Regulatory Liabilities	\$ 2,736	\$ 865	\$ 1,646
Total Current Regulatory Liabilities (4)	\$ 44	\$ 15	\$ 30
Total Non-Current Regulatory Liabilities	\$ 2,692	\$ 850	\$ 1,616

	December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC
	(in millions)		
Regulatory Assets:			
Future amounts recoverable from ratepayers related to:			
Benefit obligations (1)	\$ 373	\$ —	\$ 4
Asset retirement obligations & other	304	80	188
Net deferred income taxes	144	47	69
Total future amounts recoverable from ratepayers	821	127	261
Amounts deferred for future recovery related to:			
Cost recovery riders	145	—	83
Hurricanes and February 2021 Winter Storm Event Restoration Costs	145	145	—
May 2024 Storm Events	86	86	—
Hurricane Beryl	458	458	—
Hurricane Francine	19	19	—
Other regulatory assets	177	87	74
Decoupling	12	—	12
TEEEF	71	71	—
Unrecognized equity return (2)	(115)	(77)	(30)
Total amounts deferred for future recovery	998	789	139
Amounts currently recovered in customer rates related to:			
Authorized trackers and cost deferrals	600	47	440
Securitized regulatory assets	343	—	—
Unamortized loss on reacquired debt and hedging	93	63	10
Gas recovery costs	122	—	122
Decoupling	38	—	38
Extraordinary gas costs	133	—	133
Regulatory assets related to TCJA	47	47	—
Hurricanes and February 2021 Winter Storm Event Restoration Costs	31	5	26
Other regulatory assets	34	—	34
Benefit obligations	4	4	—
TEEEF	219	219	—
Unrecognized equity return (2)	(136)	(17)	(62)
Total amounts recovered in customer rates	1,528	368	741
Total Regulatory Assets	\$ 3,347	\$ 1,284	\$ 1,141
Total Current Regulatory Assets	\$ 239	\$ —	\$ 238
Total Non-Current Regulatory Assets	\$ 3,108	\$ 1,284	\$ 903
Regulatory Liabilities:			
Regulatory liabilities related to TCJA	\$ 1,346	\$ 673	\$ 501
Estimated removal costs	1,247	—	1,191
Other regulatory liabilities	454	195	235
Total Regulatory Liabilities	\$ 3,047	\$ 868	\$ 1,927
Total Current Regulatory Liabilities (4)	\$ 48	\$ 7	\$ 40
Total Non-Current Regulatory Liabilities	\$ 2,999	\$ 861	\$ 1,887

(1) Pension and postretirement-related regulatory assets balances are actuarially valued annually.

(2) Represents the following: (a) CenterPoint Energy's allowed equity return on post in-service carrying cost generally associated with investments in SIGECO; (b) Houston Electric's allowed equity return on TEEEF costs and storm restoration costs; and (c) CERC's allowed equity return on post in-service carrying cost associated with certain distribution facilities replacements expenditures in Texas and for Indiana Gas.

(3) Of the \$1.5 billion, \$762 million and \$289 million currently being recovered in customer rates related to CenterPoint Energy, Houston Electric and CERC, respectively, \$790 million, \$733 million and \$48 million is earning a return, respectively. The weighted average recovery period of regulatory assets currently being recovered in base rates, not earning a return, which totals \$729 million, \$29 million and \$241 million for CenterPoint Energy, Houston Electric

and CERC, respectively, is 13 years, 24 years and 6 years, respectively. Regulatory assets not earning a return with perpetual or undeterminable lives have been excluded from the weighted average recovery period calculation.

(4) Current regulatory liabilities are included in Other current liabilities in each of the Registrants' respective Consolidated Balance Sheets.

The table below reflects the amount of allowed equity return recognized by each Registrant in its Statements of Consolidated Income for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Allowed equity return recognized	\$ 25	\$ 20	\$ 4	\$ 23	\$ 20	\$ 2	\$ 41	\$ 38	\$ 2

February 2021 Winter Storm Event

In February 2021, certain of the Registrants' jurisdictions experienced an extreme and unprecedented winter weather event that resulted in prolonged freezing temperatures, which impacted their businesses. The February 2021 Winter Storm Event impacted wholesale prices of CenterPoint Energy's and CERC's natural gas purchases and their ability to serve customers in their natural gas service territories, including due to the reduction in available natural gas capacity and impacts to CenterPoint Energy's and CERC's natural gas supply portfolio activities, and the effects of weather on their systems and their ability to transport natural gas, among other things. The overall natural gas market, including the markets from which CenterPoint Energy and CERC sourced a significant portion of their natural gas for their operations, experienced significant impacts caused by the February 2021 Winter Storm Event, resulting in extraordinary increases in the cost of natural gas purchased by CenterPoint Energy and CERC of approximately \$2 billion. CenterPoint Energy and CERC have completed recovery of natural gas costs in Indiana and Texas, and continue to recover the natural gas cost in Minnesota. As of December 31, 2025, each of CenterPoint Energy and CERC had recorded a current regulatory asset of \$70 million associated with the February 2021 Winter Storm Event. As of December 31, 2024, each of CenterPoint Energy and CERC had recorded current regulatory assets of \$67 million and non-current regulatory assets of \$67 million associated with the February 2021 Winter Storm Event.

As of December 31, 2025 and 2024, as authorized by the PUCT, both CenterPoint Energy and Houston Electric had each recorded a regulatory asset of \$7 million and \$8 million, respectively, for bad debt expenses resulting from REPs' default on their obligation to pay delivery charges to Houston Electric net of collateral. Additionally, both CenterPoint Energy and Houston Electric had each recorded a regulatory asset of \$17 million and \$19 million as of December 31, 2025 and 2024, respectively, for reimbursement of costs associated with the February 2021 Winter Storm Event. Each of the aforementioned regulatory assets are being amortized over five years beginning April 28, 2025, which was the date that rates became effective following the PUCT's final order in the Houston Electric rate case.

See Note 14(c) for further information regarding litigation related to the February 2021 Winter Storm Event.

Texas Public Securitization

The Texas Natural Gas Securitization Finance Corporation issued customer rate relief bonds in March 2023, and on March 23, 2023, CenterPoint Energy and CERC, collectively, received approximately \$1.1 billion in cash proceeds from the issuance and sale of the state's customer rate relief bonds. As CenterPoint Energy and CERC have no future financial obligations for the repayment of the state's customer rate relief bonds, the customer rate relief bonds are not recorded on CenterPoint Energy's or CERC's balance sheets. The \$1.1 billion in cash proceeds from the state's customer rate relief bonds is considered to be a government grant. The state's customer rate relief bonds are backed in part by customer rate relief property, including customer rate relief charges, which are non-bypassable uniform monthly volumetric charges to be paid by all existing and future sales customers as a component of each regulated utility's gas cost, separate from their base rate. CERC only acts as a collection agent, whose duties include management, servicing and administration of a portion of the customer rate relief property which is associated with the customer rate relief charge imposed on customers of CERC under the guidance and direction from the Railroad Commission. The Texas Natural Gas Securitization Finance Corporation, and not CenterPoint Energy or CERC, is the owner of the customer rate relief property. The assets of the Texas Natural Gas Securitization Finance Corporation are not available to pay creditors of CenterPoint Energy, CERC, or their affiliates. While the customer rate relief charges will be included by CERC in their monthly billings, the billing amount is established by the Railroad Commission. CERC will remit all

customer rate relief charges collected to the financing entity set up by the Railroad Commission. Therefore, the collection and servicing of customer rate relief charges have no impact on the respective Statements of Consolidated Income of CenterPoint Energy or CERC.

As U.S. GAAP has no specific accounting guidance for government grants or assistance, the cash proceeds from the state's customer rate relief bonds were accounted for as a government grant by analogy to the grant model under IAS 20—Accounting for Government Grants and Disclosures of Government Assistance. CenterPoint Energy and CERC reflect the proceeds from the grant as a deduction to natural gas costs and recognized the \$1.1 billion of cash proceeds from the state's customer rate relief bonds within Utility natural gas expense on their respective Statements of Consolidated Income in the year ended December 31, 2023, net of the recognition of natural gas cost related to relieving CenterPoint Energy and CERC's regulatory assets related to the February 2021 Winter Storm Event in the same period.

Indiana Electric Securitization of Generation Retirements (CenterPoint Energy)

On January 4, 2023, the IURC issued an order in accordance with Indiana Senate Enrolled Act 386 authorizing the issuance of up to \$350 million in securitization bonds to securitize qualified costs associated with the retirements of Indiana Electric's A.B. Brown coal-fired generation facilities. Accordingly, CenterPoint Energy determined that the retirement of property, plant and equipment became probable upon the issuance of the order. No loss on abandonment was recognized in connection with issuance of the order as there was no disallowance of all or part of the cost of the abandoned property, plant and equipment. In the first quarter of 2023, upon receipt of the order, CenterPoint Energy reclassified property, plant and equipment to be recovered through securitization to a regulatory asset and such amounts earned a full return until subsequently recovered through securitization, as described below.

The SIGECO Securitization Subsidiary issued \$341 million aggregate principal amount of the SIGECO Securitization Bonds on June 29, 2023 and used a portion of the net proceeds from the issuance of the SIGECO Securitization Bonds to purchase the securitization property from SIGECO. No gain or loss was recognized.

The SIGECO Securitization Bonds are secured by the securitization property, which includes the right to recover, through non-bypassable securitization charges payable by SIGECO's retail electric customers, the qualified costs of SIGECO authorized by the IURC order. The SIGECO Securitization Subsidiary, and not SIGECO, is the owner of the securitization property, and the assets of the SIGECO Securitization Subsidiary are not available to pay the creditors of SIGECO or its affiliates, other than the SIGECO Securitization Subsidiary. SIGECO has no payment obligations with respect to the SIGECO Securitization Bonds except to remit collections of securitization charges as set forth in a servicing agreement between SIGECO and the SIGECO Securitization Subsidiary. The non-bypassable securitization charges are subject to a true-up mechanism.

TEEEF (CenterPoint Energy and Houston Electric)

Pursuant to Texas legislation passed in 2021, Houston Electric entered into two leases for medium (5.7 MW) and large (27 MW to 32 MW) TEEEF. Houston Electric defers costs associated with the short-term and long-term leases that are probable of recovery and would otherwise be charged to expense in a regulatory asset, including allowed debt returns, and determined that such regulatory assets remain probable of recovery as of December 31, 2025. Expenses associated with the short-term lease, including carrying costs, were deferred in a regulatory asset as a recoverable cost under the 2021 Texas legislation and totaled \$78 million and \$89 million as of December 31, 2025 and 2024, respectively. Expenses associated with the long-term lease, including variable costs associated with the operation and maintenance of the TEEEF, depreciation expense on the right of use asset and carrying costs, are deferred in a regulatory asset as a recoverable cost under the 2021 Texas legislation and totaled \$123 million and \$158 million as of December 31, 2025 and 2024, respectively.

Right of use finance lease assets, such as assets acquired under the long-term leases that are still included in the rate base of the regulated utility, are evaluated for impairment under the long-lived asset impairment model by assessing if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. Houston Electric continues to monitor the ongoing proceedings and did not record any impairments or disallowances on its right of use assets or TEEEF regulatory assets during the years ended December 31, 2025 or 2024.

Effective January 1, 2023, all medium and large TEEEF was leased under the long-term lease agreement. The long-term lease agreement includes up to 519 MW of TEEEF, all of which was delivered as of December 31, 2022, triggering lease commencement at delivery, with an initial term ending in 2029 for all such TEEEF leases. The remaining finance lease liability associated with the commenced long-term TEEEF agreement was not significant as of December 31, 2025 and 2024 and relates

to removal costs that will be incurred at the end of the lease term. As of December 31, 2025, Houston Electric had secured a first lien on all the assets leased under the prepayment agreement.

On December 19, 2024, Houston Electric announced a proposal to release its 15 large TEEEF units to ERCOT at CPS Energy facilities to serve the greater San Antonio region for a period of up to two years. On April 18, 2025, a proposal was filed with the PUCT (Docket 57980) seeking approval of the aforementioned release to ERCOT and CPS Energy, a corresponding reduction to TEEEF fleet capacity and a rate reduction to reflect the removal of the 15 large TEEEF units from Houston Electric's TEEEF fleet. On June 4, 2025, Houston Electric entered into the ERCOT Transaction, subject to PUCT approval in Docket 57980, to release the 15 large TEEEF units to the San Antonio area until March 2027 unless terminated earlier pursuant to the provisions of the ERCOT Transaction, during which time Houston Electric will not receive revenue or profit from ERCOT and will not charge Houston-area customers for such TEEEF units while they remain in the San Antonio area serving ERCOT. Following the completion of service in the San Antonio area, Houston Electric anticipates that it would complete one or more future transactions involving the large TEEEF units; because the TEEEF units would not be available to serve customers during such time, Houston Electric plans to continue to not charge customers for these units for any future periods. On June 5, 2025, certain intervenors submitted a joint request for hearing. On July 9, 2025, the PUCT referred this docket to the SOAH. On October 13, 2025, intervenor testimony was filed. On November 21, 2025 Houston Electric filed supplemental testimony proposing removal of its five medium TEEEF units from its fleet and rates. On February 13, 2026, Houston Electric requested continued abatement until February 27, 2026 due to continued settlement discussions. Following removal of the 15 large TEEEF units from customer rates, such TEEEF units are subject to impairment testing under ASC 360.

On September 11, 2024, the TCA filed a complaint with the PUCT requesting that the PUCT modify its rulings with respect to its prior decisions related to Houston Electric's TEEEF filings made in 2022 and 2023. Specifically, the TCA requested that the PUCT end cost recovery and return on investment on all the large up to 32 MW and medium 5.7 MW TEEEF units approved in Docket 53442. On June 29, 2025, Order No. 9 was issued, to abate this complaint case until a final order is issued in Docket 57980.

Pursuant to Texas legislation passed in 2023, Houston Electric has entered into contractual arrangements to facilitate access to small (200 kW to 1,250 kW) TEEEF units. In January, 2025, the PUCT adopted the TEEEF Rule, which refined the scope of TEEEF filings that can be made pursuant to applicable Texas regulations, and in February 2026, the TEEEF Rule was amended pursuant to Texas Senate Bill 231 to, among other things, prohibit TDUs from entering into, renewing or extending leases for TEEEF units unless such units have a maximum generation capacity of 5 or fewer MW and are rapidly deployable. The TEEEF Rule has specific provisions relating to when and how utilities must request PUCT authorization to lease TEEEF units, and it generally requires a utility to obtain preapproval prior to renewing or entering into a new lease of TEEEF units, with exceptions for emergency situations or if the lease includes a provision allowing for the alteration of the lease based on applicable PUCT orders or rules. Houston Electric believes that it continues to need small TEEEF units, and on May 27, 2025, Houston Electric filed an application pursuant to the TEEEF Rule requesting preapproval to enter into two leases for a combined approximately 20 MW of TEEEF capacity comprised of 36 small TEEEF units, each with a capacity range of 200 kW to 1,250 kW, for respective terms of 36 months. Approval of Houston Electric's request in this filing will have no cost impact on customers at this time because cost determination will occur in a future proceeding. On October 13, 2025, Houston Electric filed errata and supplemental testimony to modify its application to instead request preapproval of just one lease for all 36 small TEEEF units. On December 3, 2025, Houston Electric filed a stipulation and settlement agreement. On January 6, 2026, Houston Electric provided the PUCT a proposed order. These proceedings remain ongoing and, until PUCT preapproval is received, Houston Electric plans to maintain the current contractual arrangement providing access to the small TEEEF units on a month-to-month basis.

May 2024 Storm Events

Houston Electric's electric delivery system suffered significant damage as a result of the May 2024 Storm Events. As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole-mounted equipment that comprise Houston Electric's transmission and distribution system are not covered by property insurance.

On November 8, 2024, Houston Electric filed an Application for Determination of System Restoration Costs with the PUCT to determine the reasonableness and necessity of approximately \$502 million of costs (including estimated case processing expenses and carrying costs) incurred or expected to be incurred to restore service following the May 2024 Storm Events. On March 19, 2025, Houston Electric filed a settlement agreement with the PUCT, under which Houston Electric would be entitled to recover a total of \$396 million in distribution-related costs relating to the May 2024 Storm Events, along with carrying costs from the date those costs were incurred until system restoration bonds are issued. The settlement agreement also provided for the recovery of \$29 million in transmission-related costs related to the May 2024 Storm Events that will be

eligible for recovery through existing mechanisms established to recover transmission costs. Houston Electric agreed to defer \$17.5 million of its distribution-related costs to the Hurricane Beryl cost determination proceeding and further agreed to an overall \$10 million reduction in costs as part of the settlement agreement. A final order approving the settlement agreement was issued by the PUCT on April 24, 2025. On January 24, 2025, Houston Electric filed a request for a Financing Order for the distribution costs included in the November 8, 2024 Application for Determination of System Restoration Costs. On April 23, 2025, Houston Electric filed a settlement agreement with the PUCT, under which Houston Electric would be entitled to securitize the approved distribution-related costs. A final order approving the settlement agreement was issued by the PUCT on June 5, 2025. The PUCT issued an irrevocable Financing Order on June 5, 2025, which became final and non-appealable on June 20, 2025.

In connection with the securitization of the system restoration costs incurred in connection with the May 2024 Storm Events, on June 20, 2025, Houston Electric and Restoration Bond Company II filed a registration statement, as amended on August 13, 2025 and as further amended on August 27, 2025, on Form SF-1 under the Securities Act with the SEC registering the public offering and sale of up to approximately \$401.5 million aggregate principal amount of the Restoration Bond Company II Securitization Bonds. The registration statement became effective on September 8, 2025. See Note 12 for additional detail on the issuance of the Restoration Bond Company II Securitization Bonds.

Hurricane Beryl and Subsequent Storm Events

In 2024 and early 2025, Houston Electric's service territory was damaged as a result of Hurricane Beryl and certain other significant storms. Houston Electric is deferring the related system restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. Houston Electric is seeking to recover the system restoration costs (or a portion thereof) through the issuance and sale of non-recourse securitization bonds for distribution-related costs. However, there can be no assurance that the system restoration costs will be recovered in the amounts expected or on the expected timeline.

On May 2, 2025, Houston Electric filed an Application for Determination of System Restoration Costs with the PUCT to determine the reasonableness and necessity of approximately \$1.3 billion of costs (including estimated case processing expenses and carrying costs) incurred or expected to be incurred to restore service following Hurricane Beryl and certain other significant storms. Intervenor and PUCT staff subsequently filed direct testimony, and intervenor and PUCT staff disallowance positions totaled about \$298.8 million and \$4.7 million, respectively. Houston Electric subsequently filed rebuttal testimony. On August 14, 2025, Houston Electric filed a settlement agreement with the PUCT, under which Houston Electric would be entitled to recover a total of \$1.1 billion in distribution-related costs, along with carrying costs from the date those costs were incurred until the system restoration bonds are issued. The settlement agreement also provided for the recovery of \$13 million in transmission-related costs that will be eligible for recovery through existing mechanisms established to recover transmission costs. Additionally, the settlement agreement provided that Houston Electric would defer \$78 million of its distribution-related costs to a regulatory asset and could request recovery and, if eligible, securitization of the deferral in a future rate case. Houston Electric further agreed as part of the settlement agreement to an overall \$22 million reduction in distribution-related costs, which is comprised of shareholder equity carrying costs, and a \$440,000 reduction in transmission-related costs, which is also comprised of shareholder equity carrying costs. On October 2, 2025, the PUCT voted to approve the settlement agreement with a modification to remove municipal legal fees and consulting and non-consulting fees from the securitization amount and defer such costs in a regulatory asset for recovery in a future ratemaking proceeding. On October 22, 2025, Houston Electric filed a letter to affirm the removal of \$2.9 million of municipal legal fees and consulting and non-consulting fees from the securitization amount and defer these costs until a future ratemaking proceeding. A final order was issued by the PUCT on October 23, 2025.

On June 20, 2025, Houston Electric filed a request for a Financing Order for the distribution-related costs included in the May 2, 2025 Application for Determination of System Restoration Costs. On August 19, 2025, Houston Electric filed a settlement agreement with the PUCT, under which Houston Electric would be entitled to securitize the approved distribution-related costs. The settlement agreement also reduced the requested upfront qualified costs for printing materials by \$25,000 and legal expenses by \$125,000. The PUCT issued an irrevocable Financing Order on October 23, 2025, which became final and non-appealable on November 7, 2025. In connection with the securitization of the system restoration costs approved in the Financing Order, Houston Electric and Restoration Bond Company III filed a registration statement, as amended on January 27, 2026, on Form SF-1 under the Securities Act with the SEC registering the public offering and sale of up to approximately \$1.193 billion aggregate principal amount of Series 2026-A Senior Secured System Restoration Bonds. The registration statement became effective on January 30, 2026. Houston Electric anticipates receiving the net proceeds from the sale of the Series 2026-A Senior Secured System Restoration Bonds on February 26, 2026. See Note 20 for additional detail on the offering of the Series 2026-A Senior Secured System Restoration Bonds.

See Note 14(c) for further information regarding litigation related to Hurricane Beryl.

(8) Stock-Based Incentive Compensation Plans and Employee Benefit Plans

(a) Stock-Based Incentive Compensation Plans (CenterPoint Energy)

CenterPoint Energy has LTIPs that provide for the issuance of stock-based incentives, including stock options, performance awards, restricted stock unit awards and restricted and unrestricted stock awards to officers, employees and non-employee directors. Approximately 34 million shares of Common Stock are authorized under these plans for awards as of December 31, 2025. CenterPoint Energy issues new shares of its Common Stock to satisfy stock-based payments related to LTIPs. Equity awards are granted to employees without cost to the participants.

Compensation costs for the performance awards and stock unit awards granted under LTIPs are measured using fair value and expected achievement levels on the grant date. For performance awards with operational goals, the achievement levels are revised as goals are evaluated. The fair value of awards granted to employees is based on the closing stock price of CenterPoint Energy's Common Stock on the grant date. The compensation expense is recorded on a straight-line basis over the vesting period. Forfeitures are estimated on the date of grant based on historical averages and estimates are updated periodically throughout the vesting period.

The performance awards granted in 2025, 2024 and 2023 are distributed based upon the achievement of certain performance conditions or market conditions over a three-year performance cycle. The performance conditions are based on CenterPoint Energy's cumulative adjusted EPS and, for performance awards granted in 2024 and 2023, certain carbon emissions reduction goals. The market condition is based on CenterPoint Energy's total shareholder return relative to a specified peer group. Upon vesting, shares under the performance awards, as determined based on achievement of the applicable performance goals, are issued to the participants along with the value of dividend equivalents earned over the performance cycle.

The stock unit awards granted in 2025, 2024 and 2023 are service-based and subject to CenterPoint Energy's achievement of positive operating income for the last full calendar year preceding the applicable vesting date. Stock units awards granted in 2025 and 2024 vest under a three-year ratable vesting schedule, with one-third vesting as of each of the first three anniversaries of the grant date. Stock unit awards granted in 2023 cliff vest at the end of a three-year period. Each vesting under either the three-year ratable or cliff vesting schedule is subject to the achievement of the performance goal. Upon vesting, shares under the stock unit awards are issued to the participants along with the value of dividend equivalents earned over the applicable vesting period. Non-employee directors are granted stock awards that are vested immediately upon grant.

The following table summarizes CenterPoint Energy's expenses related to LTIPs for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
LTIP compensation expense (1)	\$ 48	\$ 34	\$ 65
Income tax benefit recognized	11	8	15
Actual tax benefit realized for tax deductions	13	19	17

(1) Included in Operation and maintenance expense in CenterPoint Energy's Statements of Consolidated Income, net of any amounts capitalized.

The following tables summarize CenterPoint Energy's LTIP activity for the year ended December 31, 2025:

	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (2) (Millions)
Performance Awards (1)				
Outstanding and nonvested as of December 31, 2024	4,908	\$ 28.14		
Granted	1,605	33.13		
Forfeited or canceled	(380)	29.83		
Vested and released to participants	(1,512)	26.91		
Outstanding and nonvested as of December 31, 2025	<u>4,621</u>	\$ 30.06	1	\$ 139
Stock Unit Awards				
Outstanding and nonvested as of December 31, 2024	1,117	\$ 28.20		
Granted	724	35.40		
Forfeited or canceled	(70)	30.30		
Vested and released to participants	(551)	28.83		
Outstanding and nonvested as of December 31, 2025	<u>1,220</u>	\$ 32.25	0.3	\$ 47

(1) Reflects maximum performance achievement.

(2) Reflects the impact of current expectations of achievement and stock price as of December 31, 2025.

Additional information related to the Performance Awards and Stock Unit Awards was as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
(in millions, except for per unit amounts)			
Performance Awards			
Weighted-average grant date fair value per unit of awards granted	\$ 33.13	\$ 27.92	\$ 29.18
Total intrinsic value of awards received by participants	38	51	47
Vested grant date fair value	30	40	37
Stock Unit Awards			
Weighted-average grant date fair value per unit of awards granted	\$ 35.40	\$ 28.25	\$ 30.83
Total intrinsic value of awards received by participants	19	33	28
Vested grant date fair value	16	30	23

As of December 31, 2025, there was \$53 million of total unrecognized compensation cost related to nonvested performance and stock unit awards which is expected to be recognized over a weighted-average period of 2.0 years.

(b) Pension Benefits (CenterPoint Energy)

CenterPoint Energy maintains a non-contributory qualified defined benefit pension plan covering certain eligible employees, which is closed to new participants. CenterPoint Energy also maintains three additional qualified defined benefit pension plans, two of which are closed to new participants and one of which is frozen, that cover certain eligible employees and retirees of Vectren and its subsidiaries and former subsidiaries and are primarily non-contributory. In addition to the qualified defined benefit pension plans, CenterPoint Energy maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's qualified pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. CenterPoint Energy also maintains a frozen non-qualified supplemental retirement plan covering certain former executives of Vectren.

CenterPoint Energy's net periodic cost includes the following components relating to pension plans, including the non-qualified benefit plans, for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Service cost (1)	\$ 23	\$ 25	\$ 25
Interest cost (2)	79	73	76
Expected return on plan assets (2)	(80)	(75)	(76)
Amortization of net loss (2)	27	28	28
Net periodic cost	<u>\$ 49</u>	<u>\$ 51</u>	<u>\$ 53</u>

(1) Included in Operation and maintenance expense in CenterPoint Energy's Statements of Consolidated Income, net of amounts capitalized and regulatory deferrals.

(2) Included in Other income (expense), net in CenterPoint Energy's Statements of Consolidated Income, net of regulatory deferrals.

CenterPoint Energy used the following assumptions to determine net periodic cost relating to pension benefits for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
Discount rate	5.60 %	4.95 %	5.15 %
Expected return on plan assets	7.00	6.50	6.50
Rate of increase in compensation levels	4.79	4.97	4.99

In determining net periodic benefit cost, CenterPoint Energy uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets except for two of Vectren's qualified defined benefit pension plans which use a market related value of assets.

The measurement dates for plan assets and benefit obligations were December 31, 2025 and 2024. The following table summarizes changes in the benefit obligation, changes in plan assets, the amounts recognized in the Consolidated Balance Sheets as well as the key actuarial assumptions of CenterPoint Energy's pension plans for the periods presented:

	December 31, 2025	December 31, 2024
	(in millions, except for actuarial assumptions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	\$ 1,477	\$ 1,548
Service cost	23	25
Interest cost	79	73
Benefits paid	(167)	(127)
Actuarial (gain) loss (1)	74	(42)
Benefit obligation, end of year	1,486	1,477
Change in Plan Assets		
Fair value of plan assets, beginning of year	1,132	1,204
Employer contributions	117	30
Benefits paid	(167)	(127)
Actual investment return	132	25
Fair value of plan assets, end of year	1,214	1,132
Funded status, end of year	\$ (272)	\$ (345)
Amounts Recognized in Balance Sheets		
Other non-current assets	\$ 9	\$ 7
Other current liabilities	(6)	(7)
Benefit obligations	(275)	(345)
Net liability, end of year	\$ (272)	\$ (345)
Actuarial Assumptions		
Discount rate (2)	5.35 %	5.60 %
Expected return on plan assets (3)	7.00	7.00
Rate of increase in compensation levels	4.66	4.79
Interest crediting rate	3.75	3.00

- (1) Significant sources of actuarial loss for 2025 include the decrease in discount rate from 5.60% to 5.35%, partially offset by gains due to actual return on plan assets exceeding expected return on plan assets.
- (2) The discount rate assumption was determined by matching the projected cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.
- (3) The expected rate of return assumption was developed using the targeted asset allocation of CenterPoint Energy's plans and the expected return for each asset class.

The following table displays pension benefits related to CenterPoint Energy's pension plans that have accumulated benefit obligations in excess of plan assets for the periods presented:

	December 31, 2025		December 31, 2024	
	Pension (Qualified)	Pension (Non-qualified)	Pension (Qualified)	Pension (Non-qualified)
	(in millions)			
Accumulated benefit obligation	\$ 1,443	\$ 41	\$ 1,431	\$ 44
Projected benefit obligation	1,445	41	1,433	44
Fair value of plan assets	1,214	—	1,132	—

The accumulated benefit obligation for all defined benefit pension plans on CenterPoint Energy's Consolidated Balance Sheets was \$1,484 million and \$1,475 million as of December 31, 2025 and 2024, respectively.

(c) *Postretirement Benefits*

CenterPoint Energy provides certain healthcare and life insurance benefits for certain eligible retired employees on both a contributory and non-contributory basis. CenterPoint Energy, through Vectren, also maintains a postretirement benefit plan that provides health care and life insurance benefits, which are a combination of self-insured and fully insured programs, to eligible Vectren retirees of Vectren and its subsidiaries and former subsidiaries on both a contributory and non-contributory basis.

Postretirement benefits are accrued over the active service period of employees. The net postretirement benefit cost includes the following components for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Service cost (1)	\$ 1	\$ —	\$ —	\$ 1	\$ —	\$ 1	\$ 1	\$ —	\$ 1
Interest cost (2)	13	6	5	13	5	4	13	5	5
Expected return on plan assets (2)	(6)	(4)	(1)	(6)	(4)	(1)	(5)	(4)	(1)
Amortization of prior service cost (credit) (2)	(2)	(5)	2	(2)	(5)	2	(2)	(5)	2
Amortization of net gain (2)	(10)	(5)	(3)	(8)	(4)	(3)	(8)	(4)	(3)
Net postretirement benefit cost (credit)	<u>\$ (4)</u>	<u>\$ (8)</u>	<u>\$ 3</u>	<u>\$ (2)</u>	<u>\$ (8)</u>	<u>\$ 3</u>	<u>\$ (1)</u>	<u>\$ (8)</u>	<u>\$ 4</u>

- (1) Included in Operation and maintenance expense in each of the Registrants' respective Statements of Consolidated Income, net of amounts capitalized and regulatory deferrals.
(2) Included in Other income (expense), net in each of the Registrants' respective Statements of Consolidated Income, net of regulatory deferrals.

The following assumptions were used to determine net periodic cost relating to postretirement benefits for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Discount rate	5.60 %	5.60 %	5.60 %	4.95 %	4.95 %	4.95 %	5.15 %	5.15 %	5.15 %
Expected return on plan assets	5.78 %	5.93 %	5.35 %	5.21	5.36	4.77	5.13	5.26	4.69

The measurement dates for plan assets and benefit obligations were December 31, 2025 and 2024. The following table summarizes changes in the benefit obligation, changes in plan assets, the amounts recognized in the Consolidated Balance Sheets and the key actuarial assumptions of the postretirement plans for the periods presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
(in millions, except for actuarial assumptions)						
Change in Benefit Obligation						
Benefit obligation, beginning of year	\$ 242	\$ 104	\$ 85	\$ 263	\$ 113	\$ 93
Service cost	1	—	—	1	—	1
Interest cost	13	6	5	13	5	4
Participant contributions	5	2	2	5	2	2
Benefits paid	(26)	(10)	(11)	(21)	(8)	(9)
Plan amendment	(2)	—	(2)	—	—	—
Actuarial (gain) loss (1)	25	11	9	(22)	(9)	(8)
Other transfers	—	—	—	3	1	2
Benefit obligation, end of year	258	113	88	242	104	85
Change in Plan Assets						
Fair value of plan assets, beginning of year	103	77	26	112	86	26
Employer contributions	13	1	7	9	1	5
Participant contributions	5	2	2	5	2	2
Benefits paid	(26)	(10)	(11)	(21)	(8)	(9)
Actual investment return	11	8	2	6	4	2
Other transfers	—	—	—	(8)	(8)	—
Fair value of plan assets, end of year	106	78	26	103	77	26
Funded status, end of year	\$ (152)	\$ (35)	\$ (62)	\$ (139)	\$ (27)	\$ (59)
Amounts Recognized in Balance Sheets						
Other current liabilities	\$ (8)	\$ —	\$ (5)	\$ (8)	\$ —	\$ (4)
Benefit obligations	(144)	(35)	(56)	(131)	(27)	(55)
Net liability, end of year	<u>\$ (152)</u>	<u>\$ (35)</u>	<u>\$ (61)</u>	<u>\$ (139)</u>	<u>\$ (27)</u>	<u>\$ (59)</u>
Actuarial Assumptions						
Discount rate (2)	5.35 %	5.35 %	5.35 %	5.60 %	5.60 %	5.60 %
Expected return on plan assets (3)	5.78	5.93	5.35	5.21	5.36	4.77
Medical cost trend rate assumed for the next year - Pre-65	7.00	7.00	7.00	6.75	6.75	6.75
Medical/prescription drug cost trend rate assumed for the next year - Post-65	8.36	8.36	8.36	13.74	13.74	13.74
Prescription drug cost trend rate assumed for the next year - Pre-65	12.00	12.00	12.00	10.00	10.00	10.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	4.50	4.50	4.50	4.50	4.50	4.50
Year that the cost trend rates reach the ultimate trend rate - Pre-65	2035	2035	2035	2034	2034	2034
Year that the cost trend rates reach the ultimate trend rate - Post-65	2035	2035	2035	2034	2034	2034

(1) Significant sources of actuarial loss for 2025 include the decrease in discount rate from 5.60% to 5.35%, updated claims and demographic review.

(2) The discount rate assumption was determined by matching the projected cash flows of the plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.

(3) The expected rate of return assumption was developed using the targeted asset allocation of the plans and the expected return for each asset class.

(d) Accumulated Other Comprehensive Income (Loss) (CenterPoint Energy and CERC)

CenterPoint Energy recognizes the funded status of its pension and other postretirement plans on its Consolidated Balance Sheets. To the extent this obligation exceeds amounts previously recognized in the Statements of Consolidated Income, CenterPoint Energy records a regulatory asset for that portion related to its rate-regulated utilities. To the extent that excess liability does not relate to a rate-regulated utility, the offset is recorded as a reduction to equity in accumulated other comprehensive income.

Amounts recognized in accumulated other comprehensive loss (income) consist of the following for the periods presented:

	December 31, 2025			December 31, 2024		
	Pension Benefits	Postretirement Benefits	CERC	Pension Benefits	Postretirement Benefits	CERC
	CenterPoint Energy	CenterPoint Energy		CenterPoint Energy	CenterPoint Energy	
	(in millions)					
Unrecognized actuarial loss (gain)	\$ 53	\$ (29)	\$ (24)	\$ 52	\$ (34)	\$ (26)
Unrecognized prior service cost	—	7	6	—	9	8
Net amount recognized in accumulated other comprehensive loss (income)	\$ 53	\$ (22)	\$ (18)	\$ 52	\$ (25)	\$ (18)

The changes in plan assets and benefit obligations recognized in other comprehensive income for the year ended December 31, 2025 are as follows:

	Pension Benefits	Postretirement Benefits	
	CenterPoint Energy	CenterPoint Energy	CERC
	(in millions)		
Net actuarial loss (gain)	\$ 2	\$ 4	\$ (2)
Amortization of net actuarial loss (gain)	(1)	(3)	(2)
Amortization of prior service cost	—	1	1
Total recognized in comprehensive income	\$ 1	\$ 2	\$ (3)
Total recognized in net periodic costs and other comprehensive income	\$ 50	\$ 4	\$ 4

(e) Pension Plan Assets (CenterPoint Energy)

In managing the investments associated with the benefit plans, CenterPoint Energy's objective is to achieve and maintain a fully funded plan. This objective is expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, CenterPoint Energy maintained the following weighted-average allocation targets for its pension plans as of December 31, 2025:

	Minimum	Maximum
U.S. equity	24 %	34 %
International equity	12 %	22 %
Real estate	2 %	8 %
Fixed income	44 %	54 %
Cash	0 %	2 %

The following tables set forth by level, within the fair value hierarchy (as described in Note 9), CenterPoint Energy's pension plan assets at fair value as of the dates presented:

	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Cash	\$ 17	\$ —	\$ —	\$ 17	\$ 36	\$ —	\$ —	\$ 36
Equity securities:								
U.S. companies	42	—	—	42	28	—	—	28
Cash received as collateral from securities lending	86	—	—	86	88	—	—	88
Obligation to return cash received as collateral from securities lending	(86)	—	—	(86)	(88)	—	—	(88)
U.S. treasuries and government agencies	215	—	—	215	156	—	—	156
Corporate bonds:								
Investment grade or above	—	348	—	348	—	428	—	428
Mortgage-backed securities	—	2	—	2	—	12	—	12
Asset-backed securities	—	1	—	1	—	1	—	1
Municipal bonds	—	17	—	17	—	19	—	19
International government bonds	—	10	—	10	—	13	—	13
Financial instruments	—	—	—	—	—	(3)	—	(3)
Total investments at fair value	\$ 274	\$ 378	\$ —	652	\$ 220	\$ 470	\$ —	690
Investments measured by net asset value per share or its equivalent (1) (2)				562				442
Fair value of plan assets				\$ 1,214				\$ 1,132

(1) Represents investments in pooled investment funds and common collective trust funds.

(2) The amounts invested in pooled investment funds were 100% allocated to real estate. The amounts invested common collective trust funds were allocated as follows for the periods presented:

	December 31, 2025	December 31, 2024
International equities	41 %	38 %
U.S. equities	59 %	61 %
Fixed income	— %	1 %

Level 2 investments, which do not have a quoted price in active market, are valued using the market data provided by independent pricing services or major market makers, to arrive at a price a dealer would pay for the security.

The pension plans utilized both exchange traded and over-the-counter financial instruments such as futures, interest rate options and swaps that were marked to market daily with the gains or losses settled in the cash accounts. The pension plans did not include any holdings of CenterPoint Energy Common Stock as of December 31, 2025 or 2024.

(f) Postretirement Plan Assets

In managing the investments associated with the postretirement plans, the Registrants' primary objective is to preserve and improve the funded status of the plan, while minimizing volatility. This objective is expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, the Registrants maintained the following weighted-average allocation targets for the postretirement plans as of December 31, 2025:

	CenterPoint Energy		Houston Electric		CERC	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
U.S. equities	14 %	24 %	13 %	23 %	15 %	25 %
International equities	3 %	13 %	3 %	13 %	2 %	12 %
Fixed income	68 %	78 %	69 %	79 %	68 %	78 %
Cash	0 %	2 %	0 %	2 %	0 %	2 %

The following table sets forth by level, within the fair value hierarchy (as described in Note 9), the Registrants' postretirement plan assets, all of which were mutual funds, at fair value as of the dates presented:

	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
CenterPoint Energy	\$ 106	\$ —	\$ —	\$ 106	\$ 103	\$ —	\$ —	\$ 103
Houston Electric	78	—	—	78	77	—	—	77
CERC	26	—	—	26	26	—	—	26

The amounts invested in mutual funds were allocated as follows as of the dates presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
U.S. equities	20 %	19 %	22 %	19 %	18 %	21 %
International equities	9 %	9 %	8 %	7 %	8 %	7 %
Fixed income	71 %	72 %	70 %	74 %	74 %	72 %

(g) Benefit Plan Contributions

The Registrants made the following contributions in 2025 and are required to make the following minimum contributions in 2026 to the indicated benefit plans below:

	Contributions in 2025			Expected Minimum Contributions in 2026		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Qualified pension plans	\$ 110	\$ —	\$ —	\$ 71	\$ —	\$ —
Non-qualified pension plans	7	—	—	6	—	—
Postretirement benefit plans	13	1	7	9	—	5

Benefit payments are expected to be paid by the pension and postretirement benefit plans as follows for the periods presented:

	Pension Benefits		Postretirement Benefits		
	CenterPoint Energy	CenterPoint Energy	Houston Electric	CERC	
	(in millions)				
2026	\$ 140	\$ 19	\$ 8	\$ 7	
2027	145	20	9	7	
2028	138	20	9	7	
2029	133	21	10	7	
2030	131	22	10	7	
2031-2035	596	104	48	34	

(h) Savings Plan

CenterPoint Energy maintains the CenterPoint Energy Savings Plan, a tax-qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Code and an employee stock ownership plan under Section 4975(e)(7) of the Code. Under the plan, participating employees may make pre-tax or Roth contributions and after-tax contributions up to certain federally mandated limits. Participating Registrants provide matching contributions and, as of January 1, 2020, for certain eligible employees, non-elective contributions up to certain limits.

The CenterPoint Energy Savings Plan has significant holdings of Common Stock. As of December 31, 2025, 6,443,228 shares of Common Stock were held by the savings plan, which represented approximately 6% of its investments. Given the concentration of the investments in Common Stock, the savings plan and its participants have market risk related to this

investment. The savings plan limits the percentage of future contributions that can be invested in Common Stock to 25% and prohibits transfers of account balances where the transfer would result in more than 25% of a participant's total account balance invested in Common Stock.

CenterPoint Energy allocates the savings plan benefit expense to Houston Electric and CERC related to their respective employees. The following table summarizes the Registrants' savings plan benefit expense for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Savings plan benefit expenses (1)	\$ 75	\$ 29	\$ 22	\$ 72	\$ 27	\$ 23	\$ 67	\$ 23	\$ 20

(1) Amounts presented in the table above are included in Operation and maintenance expense in the Registrants' respective Statements of Consolidated Income and shown prior to any amounts capitalized.

(i) Other Benefits Plans

CenterPoint Energy maintains non-qualified deferred compensation plans that provide benefits payable to eligible directors, officers and select employees or their designated beneficiaries at specified future dates or upon termination, retirement or death. Benefit payments are made from the general assets of the participating Registrants or, in the case of certain plans, from a rabbi trust that is a grantor trust and remains subject to the claims of general creditors under applicable state and federal law. Amounts related to other benefit plans were included in Benefit Obligations in the Registrants' accompanying Consolidated Balance Sheets as follows for the periods presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Deferred compensation plans	\$ 17	\$ 2	\$ 1	\$ 22	\$ 3	\$ 1
Split-dollar life insurance arrangements	48	1	—	46	1	—

(j) Change in Control Agreements and Other Employee Matters

CenterPoint Energy maintains a change in control plan for the benefit of certain CenterPoint Energy officers. The plan generally provides, to the extent applicable, in the case of the occurrence of both a change in control of CenterPoint Energy and a covered termination of employment, for severance benefits of one to three times the sum of annual base salary and target annual bonus and other benefits.

As of December 31, 2025, the Registrants' employees were covered by collective bargaining agreements as follows:

	Agreement Expiration	Percentage of Employees Covered		
		CenterPoint Energy	Houston Electric	CERC
IBEW Local 66	May 2026	19 %	54 %	— %
OPEIU Local 12	December 2025	2 %	— %	3 %
Gas Workers Union Local 340	April 2030	5 %	— %	14 %
IBEW Locals 1393 and USW Locals 12213 & 7441	December 2026	3 %	— %	9 %
IBEW Locals 949	December 2030	3 %	— %	8 %
USW Locals 13-227	June 2027	5 %	— %	16 %
IBEW Local 702	June 2029	3 %	— %	— %
Teamsters Local 135/215	September 2027	— %	— %	— %
UWUA Local 175	October 2027	2 %	— %	4 %
Total		42 %	54 %	54 %

The collective bargaining agreements with IBEW Locals 1393 and USW Locals 12213 & 7441 related to Indiana Gas employees, as well as with IBEW Local 66 related to Houston Electric employees, are scheduled to expire in December 2026 (IBEW Local 1393 & USW Locals 12213 & 7441) and May 2026 (IBEW Local 66), and negotiations of these agreements are

expected to be completed before the respective expirations. The collective bargaining agreement with OPEIU Local 12 related primarily to CERC employees in Minnesota expired in December 2025 and negotiations are ongoing.

(9) Fair Value Measurements

Assets and liabilities that are recorded at fair value in the Registrants' Consolidated Balance Sheets are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are exchange-traded derivatives and equity securities.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. A market approach is utilized to value the Registrants' Level 2 interest rate derivative assets or liabilities and natural gas derivative assets or liabilities. CenterPoint Energy's Level 2 indexed debt securities derivative is valued using an option model and a discounted cash flow model, which uses projected dividends on the ZENS-Related Securities and a discount rate as observable inputs.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Registrants' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Registrants develop these inputs based on the best information available, including the Registrants' own data.

The Registrants determine the appropriate level for each financial asset and liability on a quarterly basis and recognize transfers between levels at the end of the reporting period. As of December 31, 2025 and December 31, 2024, the Registrants did not have any assets or liabilities classified as Level 3.

The following tables present information about the Registrants' assets and liabilities measured at fair value on a recurring basis as of the dates presented and indicate the fair value hierarchy of the valuation techniques utilized by the Registrants to determine such fair value:

CenterPoint Energy

	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(in millions)							
Investments in equity securities	\$ 510	\$ —	\$ —	\$ 510	\$ 561	\$ —	\$ —	\$ 561
Investments, including money market funds (1)	23	—	—	23	22	—	—	22
Total assets	\$ 533	\$ —	\$ —	\$ 533	\$ 583	\$ —	\$ —	\$ 583
Liabilities								
Indexed debt securities derivative	\$ —	\$ 564	\$ —	\$ 564	\$ —	\$ 619	\$ —	\$ 619
Total liabilities	\$ —	\$ 564	\$ —	\$ 564	\$ —	\$ 619	\$ —	\$ 619

Houston Electric

	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(in millions)							
Investments, including money market funds (2)	\$ 6	\$ —	\$ —	\$ 6	\$ 5	\$ —	\$ —	\$ 5
Total assets	\$ 6	\$ —	\$ —	\$ 6	\$ 5	\$ —	\$ —	\$ 5

CERC

	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(in millions)							
Investments, including money market funds (1)	\$ 16	\$ —	\$ —	\$ 16	\$ 15	\$ —	\$ —	\$ 15
Total assets	\$ 16	\$ —	\$ —	\$ 16	\$ 15	\$ —	\$ —	\$ 15

- (1) Primarily included in Other non-current assets in the respective Consolidated Balance Sheets.
(2) Primarily included in Prepaid expenses and other current assets in the Consolidated Balance Sheets.

Items Measured at Fair Value on a Nonrecurring Basis

As a result of classifying the Ohio Natural Gas LDC business and Louisiana and Mississippi Natural Gas LDC businesses as held for sale at December 31, 2025 and 2024, respectively, CenterPoint Energy and CERC used a market approach consisting of contractual sales price adjusted for estimated working capital and other contractual purchase price adjustments to determine the fair value of the businesses classified as held for sale, which are Level 2 inputs. Neither CenterPoint Energy nor CERC recognized any gains or losses from held for sale for the years ended December 31, 2025 and 2024. See Note 4 for further information.

Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents and investments in equity securities measured at fair value are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. Additionally, CenterPoint Energy's ZENS indexed debt securities derivative is stated at fair value and is excluded from the table below. The fair value of each debt instrument included below is determined by multiplying the principal amount of each debt instrument by a combination of historical trading prices and comparable issue data. These liabilities, which are not measured at fair value in the Registrants' Consolidated Balance Sheets, but for which the fair value is disclosed, would be classified as Level 2 in the fair value hierarchy.

	December 31, 2025			December 31, 2024		
	CenterPoint Energy (1)	Houston Electric (1)	CERC	CenterPoint Energy (1)	Houston Electric (1)	CERC
Short-term borrowings and long-term debt, including current maturities	(in millions)					
Carrying amount	\$ 22,980	\$ 10,079	\$ 4,717	\$ 20,961	\$ 8,822	\$ 5,184
Fair value	22,377	9,292	4,711	19,597	7,746	5,032

- (1) Includes Securitization Bonds.

(10) Equity Securities and Indexed Debt Securities (ZENS) (CenterPoint Energy)

(a) Equity Securities

Gains and losses on equity securities, net of transaction costs, are recorded as Gain (loss) on equity securities in CenterPoint Energy's Statements of Consolidated Income. The following table presents unrealized gains (losses), net on equity securities owned by CenterPoint Energy for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
AT&T Common	\$ 21	\$ 62	\$ (17)
Charter Common	(117)	(40)	43
WBD Common	45	(2)	5
Total unrealized gains (losses) on equity securities, net	\$ (51)	\$ 20	\$ 31

CenterPoint Energy and its subsidiaries hold shares of certain securities detailed in the table below, which are classified as trading securities. Shares of AT&T Common, Charter Common and WBD Common are expected to be held to facilitate

CenterPoint Energy's ability to meet its obligation under the ZENS. The following table represents information on CenterPoint Energy's equity securities for the periods presented:

	Shares Held at December 31,		Carrying Value at December 31,	
	2025	2024	2025	2024
			(in millions)	
AT&T Common	10,212,945	10,212,945	\$ 254	\$ 233
Charter Common	872,503	872,503	182	299
WBD Common	2,470,685	2,470,685	71	26
Other			3	3
Total			\$ 510	\$ 561

(b) ZENS

In September 1999, CenterPoint Energy issued ZENS having an original principal amount of \$1.0 billion, of which \$828 million remained outstanding as of December 31, 2025. Each ZENS is exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares attributable to such note. The number and identity of the reference shares attributable to each ZENS are adjusted for certain corporate events. CenterPoint Energy's reference shares for each ZENS consisted of the following for the periods presented:

	December 31, 2025	December 31, 2024
	(in shares)	
AT&T Common	0.7185	0.7185
Charter Common	0.061382	0.061382
WBD Common	0.173817	0.173817

On June 9, 2025, WBD announced plans to separate the company, in a tax-free transaction, into two publicly traded companies, referred to by WBD as, respectively, the "Streaming & Studios" company and the "Global Networks" company (Discovery Global). On December 5, 2025, Netflix and WBD announced they had entered into an agreement under which Netflix will acquire the "Streaming & Studio" company following the previously-announced division. Under the agreement, each WBD shareholder would receive \$23.25 in cash and \$4.50 in shares of Netflix common stock for each share of WBD Common outstanding at the closing of the transaction. On January 20, 2026, Netflix and WBD announced they had amended their agreement to be all-cash transaction. If the division and merger close, WBD Common would be exchanged for cash and Discovery Global stock and as a result, reference shares would consist of AT&T Common, Charter Common, and stock in Discovery Global.

CenterPoint Energy pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the reference shares attributable to the ZENS. The principal amount of the ZENS is subject to increases or decreases to the extent that the annual yield from interest and cash dividends on the reference shares attributable to the ZENS is less than or more than 2.309%. The adjusted principal amount is defined in the ZENS instrument as "contingent principal." As of December 31, 2025, the ZENS, having an original principal amount of \$828 million and a contingent principal amount of less than \$0.1 million, were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of the reference shares attributable to the ZENS. As of December 31, 2025, the market value of such shares was approximately \$507 million, which would provide an exchange amount of \$582 for each \$1,000 original principal amount of ZENS. At maturity of the ZENS in 2029, CenterPoint Energy will be obligated to pay in cash the higher of the contingent principal amount of the ZENS or an amount based on the then-current market value of the reference shares, which will include any additional publicly-traded securities distributed with respect to the current reference shares prior to maturity.

The ZENS obligation is bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of the reference shares at maturity). The bifurcated debt component accretes through interest charges annually up to the contingent principal amount of the ZENS in 2029. Such accretion will be reduced by annual cash interest payments, as previously described. The derivative component is recorded at fair value and changes in the fair value of the derivative component are recorded as Gain (loss) on indexed debt securities in CenterPoint Energy's Statements of Consolidated Income. Changes in the fair value of the ZENS-Related Securities held by CenterPoint Energy are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table provides summarized financial information related to CenterPoint Energy's investment in ZENS-Related Securities and each component of CenterPoint Energy's ZENS obligation for the periods presented:

	Investment in Equity Securities	Indexed Debt, net (in millions)	Indexed Debt Securities Derivative
Balance as of December 31, 2022	\$ 507	\$ 7	\$ 578
Accretion of debt component of ZENS	—	17	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(2)	—
Loss on indexed debt securities	—	—	27
Gain on ZENS-Related Securities	31	—	—
Balance as of December 31, 2023	538	5	605
Accretion of debt component of ZENS	—	16	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(2)	—
Loss on indexed debt securities	—	—	14
Gain on ZENS-Related Securities	20	—	—
Balance as of December 31, 2024	558	2	619
Accretion of debt component of ZENS	—	17	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(2)	—
Gain on indexed debt securities	—	—	(55)
Loss on ZENS-Related Securities	(51)	—	—
Balance as of December 31, 2025	\$ 507	\$ —	\$ 564

(11) Equity (CenterPoint Energy)

Dividends Declared and Paid (CenterPoint Energy)

CenterPoint Energy's dividends declared and dividends paid are as follows for the periods presented:

	Dividends Declared Per Share			Dividends Paid Per Share		
	2025	2024	2023	2025	2024	2023
Common Stock	\$ 0.890	\$ 0.830	\$ 0.780	\$ 0.880	\$ 0.810	\$ 0.770
Series A Preferred Stock (1)	\$ —	\$ —	\$ 30.625	\$ —	\$ —	\$ 61.250

(1) All of the outstanding shares of Series A Preferred Stock were redeemed during 2023 as further described below.

Common Stock (CenterPoint Energy)

(a) Underwritten Offering

On August 9, 2024, CenterPoint Energy issued 9,754,194 shares of Common Stock in an underwritten public offering at a price of \$25.36 per share, for net proceeds of \$247 million after deducting issuance costs. The proceeds from the offering were used for the repayment of a portion of CenterPoint Energy's then-outstanding commercial paper.

(b) Equity Distribution Agreement

On January 10, 2024, CenterPoint Energy entered into an Equity Distribution Agreement with certain financial institutions with respect to the offering and sale from time to time of shares of Common Stock, having an aggregate gross sales price of up to \$500 million. Sales of Common Stock may be made by any method permitted by applicable law and deemed to be an "at the market offering" as defined in Rule 415 of the Securities Act. The offer and sale of Common Stock under the Equity Distribution Agreement will terminate upon the earliest of (1) the sale of all Common Stock subject to the Equity Distribution Agreement, (2) termination of the Equity Distribution Agreement or (3) May 17, 2026.

In April 2025, CenterPoint Energy entered into separate forward sale agreements pursuant to the Equity Distribution Agreement with certain of the ATM Forward Purchasers relating to 3,277,764 shares and 680,902 shares of Common Stock at

an initial forward price of \$36.29 per share and \$36.72 per share, respectively. The gross sales price of these shares totaled approximately \$120 million and \$25 million, respectively. In connection with these sales, the ATM Forward Sellers were deemed to have received commissions of approximately \$1 million and less than \$1 million, respectively. In May 2025, CenterPoint Energy entered into a forward sale agreement with an ATM Forward Purchaser relating to 521,962 shares of Common Stock at an initial forward price of \$37.49 per share. The gross sales price of these shares totaled approximately \$20 million. In connection with these sales, the ATM Forward Seller was deemed to have received a commission of less than \$1 million. CenterPoint Energy has not received any proceeds from such sales of borrowed shares. On a settlement date or dates, if CenterPoint Energy elects to physically settle the forward sale agreements, CenterPoint Energy will issue shares of Common Stock to the counterparties at the then-applicable forward sale price. The forward price used to determine amounts due at settlement is calculated based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on certain dates specified in the forward sale agreements by specified amounts related to expected dividends on the shares of the Common Stock during the term of the forward sale agreements. If the overnight bank funding rate is less than or more than the spread on any day, the interest rate factor will result in a reduction or an increase, respectively, of the forward sale price. As initial pricing terms were based on market prices for Common Stock, no amounts were recorded at the execution of the forward sale agreements. CenterPoint Energy will receive proceeds when settlement occurs and will record the proceeds in equity.

The forward sale agreements pursuant to the Equity Distribution Agreement require CenterPoint Energy to, at its election on or prior to May 14, 2026, either (1) physically settle the transactions by issuing the total of 4,480,628 shares of Common Stock to the counterparties in exchange for cash of approximately \$165 million or (2) net settle the transactions in whole or in part through the delivery or receipt of cash or shares of Common Stock. Pursuant to such net settlement provisions, these agreements could have been settled on December 31, 2025 by CenterPoint Energy's delivery of approximately \$7.0 million of cash or 187,450 shares of Common Stock to the banking counterparties if CenterPoint Energy unilaterally elected net cash or net share settlement, respectively. As of December 31, 2025, CenterPoint Energy had approximately \$85 million of remaining capacity available under the at-the-market program.

(c) Forward Sale Agreements

In May 2025, CenterPoint Energy entered into separate forward sale agreements with certain financial institutions relating to an aggregate of 24,864,865 shares of Common Stock at an initial forward price of \$36.26 per share. On a settlement date or dates, if CenterPoint Energy elects to physically settle the forward sale agreements, CenterPoint Energy will issue shares of Common Stock to the counterparties at the then-applicable forward sale price. Each forward sale agreement provides that the initial forward sale price will be subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on each of certain dates specified in the relevant forward sale agreement by amounts related to expected dividends on shares of the Common Stock during the term of such forward sale agreement. If the overnight bank funding rate is less than or more than the spread on any day, the interest rate factor will result in a reduction or an increase, respectively, of the forward sale price. As initial pricing terms were based on market prices for Common Stock, no amounts were recorded at the execution of the forward sale agreements. CenterPoint Energy will receive proceeds when settlement occurs and will record the proceeds in equity.

The forward sale agreements require CenterPoint Energy to, at its election on or prior to February 25, 2027, either (1) physically settle the transactions by issuing the total of 24,864,865 shares of Common Stock to the counterparties in exchange for cash of \$907 million or (2) net settle the transactions in whole or in part through the delivery or receipt of cash or shares of Common Stock. Pursuant to such net settlement provisions, these agreements could also have been settled on December 31, 2025 by CenterPoint Energy's delivery of approximately \$45 million of cash or 1,161,405 shares of Common Stock to the banking counterparties if CenterPoint Energy unilaterally elected net cash or net share settlement, respectively.

Series A Preferred Stock (CenterPoint Energy)

On September 1, 2023, CenterPoint Energy redeemed all 800,000 outstanding shares of Series A Preferred Stock, in whole for cash at a redemption price of \$1,000. Income allocated to the Series A Preferred shareholders was \$50 million for the year ended December 31, 2023. The Series A Preferred Stock accrued cumulative dividends, calculated as a percentage of the stated amount per share, at a fixed annual rate of 6.125% per annum to be paid in cash if, when and as declared. If declared, dividends were payable semi-annually in arrears on each March 1 and September 1.

Accumulated Other Comprehensive Income (Loss) (CenterPoint Energy, Houston Electric and CERC)

Changes in accumulated other comprehensive income (loss) are as follows for the periods presented:

	Year Ended December 31,					
	2025			2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Beginning Balance	\$ (17)	\$ (1)	\$ 17	\$ (35)	\$ —	\$ 16
Other comprehensive income (loss) before reclassifications:						
Remeasurement of pension and other postretirement plans	(7)	(1)	(1)	16	(1)	2
Net deferred gain from cash flow hedges	—	—	—	4	—	—
Amounts reclassified from accumulated other comprehensive income (loss):						
Prior service cost (1)	1	—	1	1	—	1
Actuarial losses (gain) (1)	(2)	—	(3)	2	—	(2)
Reclassification of deferred gain from cash flow hedges realized in net income (2)	(1)	—	—	(1)	—	—
Tax benefit (expense)	—	—	1	(4)	—	—
Other comprehensive income (loss)	(9)	(1)	(2)	18	(1)	1
Ending Balance	\$ (26)	\$ (2)	\$ 15	\$ (17)	\$ (1)	\$ 17

- (1) Amounts are included in the computation of net periodic cost and are reflected in Other income (expense), net in each of the Registrants' respective Statements of Consolidated Income.
- (2) Amounts are reflected in Interest expense and other finance charges in CenterPoint Energy's Statements of Consolidated Income.

(12) Short-term Borrowings and Long-term Debt

Short-term Borrowings and Long-term Debt: The Registrants had the following short-term borrowings and long-term debt outstanding as of the dates presented:

	December 31, 2025		December 31, 2024	
	Long-Term	Current (1)	Long-Term	Current (1)
(in millions)				
CenterPoint Energy:				
ZENS due 2029 (2)	\$ —	\$ —	\$ —	\$ 2
CenterPoint Energy senior notes 1.45% to 5.25% due 2026 to 2049	2,470	1,517	3,950	—
CenterPoint Energy Junior Subordinated Notes 5.95% to 7.00% due 2055 to 2056	2,000	—	1,300	—
CenterPoint Energy pollution control bonds 5.125% due 2028 (3)	68	—	68	—
CenterPoint Energy commercial paper (4)	420	—	382	—
SIGECO first mortgage bonds 3.45% to 6.18% due 2025 to 2055 (5)	1,459	—	944	41
SIGECO Securitization Bonds 5.026% to 5.172% due 2036 to 2041 (6)	299	13	311	13
Unamortized debt issuance costs	(56)	(3)	(48)	—
Unamortized discount and premium, net	(3)	—	(6)	—
Houston Electric debt (see details below)	9,252	827	8,322	500
CERC debt (see details below)	4,657	60	5,174	10
Total CenterPoint Energy debt	\$ 20,566	\$ 2,414	\$ 20,397	\$ 566
Houston Electric:				
Short Term Borrowings:				
Term loan (7)	\$ —	\$ 500	\$ —	\$ 500
Long-term debt:				
General mortgage bonds 2.35% to 6.95% due 2026 to 2053 (8)	8,978	300	8,412	—
Other	1	—	1	—
Restoration Bond Company II Securitization Bonds 4.26% to 4.83% due 2035 to 2040 (9)	375	27	—	—
Unamortized debt issuance costs	(73)	—	(62)	—
Unamortized discount and premium, net	(29)	—	(29)	—
Total Houston Electric debt	\$ 9,252	\$ 827	\$ 8,322	\$ 500
CERC (10):				
Senior notes 1.75% to 6.625% due 2026 to 2047	\$ 4,045	\$ 60	\$ 4,520	\$ —
Indiana Gas senior notes 6.34% to 7.08% due 2025 to 2029	76	—	86	10
Commercial paper (4)	559	—	599	—
Unamortized debt issuance costs	(23)	—	(31)	—
Total CERC debt	\$ 4,657	\$ 60	\$ 5,174	\$ 10

- (1) Includes amounts due or exchangeable within one year of the date noted.
- (2) CenterPoint Energy's ZENS obligation is bifurcated into a debt component and an embedded derivative component. For additional information regarding ZENS, see Note 10(b). As ZENS are exchangeable for cash at any time at the option of the holders, these notes are classified as a current portion of long-term debt.
- (3) These pollution control bonds were secured by general mortgage bonds of Houston Electric as of December 31, 2025 and 2024 and are not reflected in Houston Electric's consolidated financial statements because of the contingent nature of the obligations.
- (4) Commercial paper issued by CenterPoint Energy and CERC Corp. has maturities up to 60 days and 30 days, respectively, and are backstopped by the respective issuer's long-term revolving credit facility. Commercial paper is classified as long-term because the termination date of the facility that backstops the commercial paper is more than one year from the balance sheet date.
- (5) The first mortgage bonds issued by SIGECO subject SIGECO's properties to a lien under the related mortgage indenture as further discussed below.
- (6) Scheduled final payment dates are November 15, 2036 and May 15, 2041. The SIGECO Securitization Bonds will be repaid over time through a securitization charge imposed on retail electric customers in SIGECO's service territory.

- (7) On November 20, 2025, Houston Electric, Mizuho Bank, Ltd., as administrative agent, and the banks party thereto entered into a First Amendment to the Term Loan Agreement, amending Houston Electric's Term Loan Agreement dated as of June 24, 2024. The First Amendment extended the maturity date of the Term Loan Agreement from December 24, 2025 to March 31, 2026.
- (8) The general mortgage bonds issued by Houston Electric subject Houston Electric's properties to a lien under the General Mortgage as further discussed below.
- (9) Scheduled final payment dates are December 15, 2035 and June 15, 2040. The Restoration Bond Company II Securitization Bonds will be repaid over time through a securitization charge imposed on retail electric customers in Houston Electric's service territory.
- (10) Issued by CERC Corp.

Debt Transactions

Debt Issuances. During 2025, the following debt instruments were issued or incurred:

Registrant	Issuance Date	Debt Instrument	Aggregate Principal Amount (in millions, except for interest rates)	Interest Rate	Maturity Date
Houston Electric (1)	February 2025	General Mortgage Bonds	\$ 500	4.80%	2030
Houston Electric (2)	August 2025	General Mortgage Bonds	600	4.95%	2035
Houston Electric (3)	September 2025	Securitization Bonds	402	4.255% - 4.826%	2035 - 2040
Total Houston Electric			1,502		
CenterPoint Energy (4)	January 2025	First Mortgage Bonds	165	5.69%	2055
CenterPoint Energy (5)	July 2025	First Mortgage Bonds	100	5.09%	2031
CenterPoint Energy (5)	July 2025	First Mortgage Bonds	105	5.52%	2035
CenterPoint Energy (6)	July 2025	2028 Convertible Senior Notes	1,000	3.00%	2028
CenterPoint Energy (7)	October 2025	First Mortgage Bonds	45	5.77%	2040
CenterPoint Energy (7)	October 2025	First Mortgage Bonds	100	6.18%	2055
CenterPoint Energy (8)	October 2025	Junior Subordinated Notes	700	5.95%	2056
Total CenterPoint Energy			\$ 3,717		

- (1) Net proceeds from Houston Electric's February 2025 issuance of general mortgage bonds, after deducting transaction expenses and fees, were approximately \$495 million, which were used for general limited liability company purposes, including capital expenditures and working capital purposes.
- (2) Net proceeds from Houston Electric's August 2025 issuance of general mortgage bonds, after deducting transaction expenses and fees, were approximately \$592 million, which were used for general limited liability company purposes, including capital expenditures and working capital purposes.
- (3) Issued by Restoration Bond Company II. Net proceeds from the September 2025 issuance of the Restoration Bond Company II Securitization Bonds, after deducting transaction expenses and fees, were approximately \$396 million, which were used to purchase the system restoration property from Houston Electric.
- (4) Issued by SIGECO. Net proceeds from SIGECO's January 2025 issuance of first mortgage bonds, after deducting transaction expenses and fees, were approximately \$164 million, which were used for the acquisition of Posey Solar.
- (5) Issued by SIGECO. Total proceeds from SIGECO's July 2025 issuance of the Series 2025B Bonds were used for general corporate purposes, including repaying short-term debt, refunding long-term debt at maturity or otherwise and funding capital expenditures.
- (6) Net proceeds from CenterPoint Energy's July 2025 issuance of convertible senior notes, after deducting transaction expenses and fees, were approximately \$987 million, which were used for general corporate purposes, including repayment of a portion of CenterPoint Energy's outstanding commercial paper and other debt.
- (7) Issued by SIGECO. Total proceeds from SIGECO's October 2025 issuance of first mortgage bonds of the Series 2025C Bonds were used for general corporate purposes, including repaying short-term debt, refunding long-term debt at maturity or otherwise and funding capital expenditures.
- (8) Net proceeds from CenterPoint Energy's October 2025 issuance of junior subordinated notes, after deducting transaction expenses and fees, were approximately \$691 million, which were used for general corporate purposes, including the repayment of a portion of CenterPoint Energy's outstanding commercial paper.

Junior Subordinated Notes due 2056. As described in the table above, in October 2025, CenterPoint Energy issued \$700 million aggregate principal amount of 5.950% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series D, due 2056

(the “Series D Notes”). Interest on the Series D Notes accrues from October 2, 2025 and is payable semiannually in arrears on April 1 and October 1 of each year, beginning on April 1, 2026, and maturing on April 1, 2036. The Series D Notes bear interest (i) from and including October 2, 2025 to, but excluding, April 1, 2031 at the rate of 5.950% per annum and (ii) from and including April 1, 2031, during each five-year period following April 1, 2031 (each such five-year period, a “Series D Interest Reset Period”), at a rate per annum equal to the Five-Year Treasury Rate (as defined in the Junior Subordinated Notes Indenture) as of two business days prior to the beginning of the applicable Series D Interest Reset Period plus a spread of 2.223%, with such rate per annum to be reset on each five-year anniversary of April 1, 2031; provided that the interest rate during any Series D Interest Reset Period will not reset below 5.950% per annum (which is the same interest rate as in effect from and including the original issue date to, but excluding, April 1, 2031). So long as no event of default (as defined in the prospectus supplement relating to the offering of the Series D Notes) with respect to the Series D Notes has occurred and is continuing, CenterPoint Energy may, at its option, defer interest payments on the Series D Notes, from time to time, for one or more deferral periods of up to 20 consecutive semiannual interest payment periods, except that no such optional deferral period (as defined in the prospectus supplement relating to the offering of the Series D Notes) may extend beyond the final maturity date of the Series D Notes or end on a day other than the day immediately preceding an interest payment date.

During any optional deferral period, CenterPoint Energy (and its majority-owned subsidiaries, as applicable) will not (subject to certain exceptions as described in the Junior Subordinated Notes Indenture): (i) declare or pay any dividends or distributions on any of CenterPoint Energy’s capital stock; (ii) redeem, purchase, acquire or make a liquidation payment with respect to any of CenterPoint Energy’s capital stock; (iii) pay any principal, interest (to the extent such interest is deferrable) or premium on, or repay, repurchase or redeem any of CenterPoint Energy’s indebtedness that ranks equally with or junior to the Series D Notes in right of payment (including debt securities of other series, such as the other series of the Junior Subordinated Notes outstanding); or (iv) make any payments with respect to any guarantees by CenterPoint Energy of any indebtedness if such guarantees rank equally with or junior to the Series D Notes in right of payment.

The Series D Notes are CenterPoint Energy’s unsecured obligations and rank junior and subordinate in right of payment to the prior payment in full of CenterPoint Energy’s existing and future Senior Indebtedness (as defined in the Junior Subordinated Notes Indenture).

2026 Convertible Senior Notes. Interest on the 2026 Convertible Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning on February 15, 2024. The 2026 Convertible Notes will mature on August 15, 2026, unless earlier converted or repurchased by CenterPoint Energy in accordance with their terms.

Prior to the close of business on the business day immediately preceding May 15, 2026, the 2026 Convertible Notes are convertible only under certain conditions. On or after May 15, 2026 until the close of business on the second scheduled trading day immediately preceding the maturity date, holders of the 2026 Convertible Notes may convert all or any portion of their 2026 Convertible Notes at any time at the conversion rate then in effect, irrespective of the conditions. CenterPoint Energy may not redeem the 2026 Convertible Notes prior to the maturity date.

Upon conversion of the 2026 Convertible Notes, CenterPoint Energy will pay cash up to the aggregate principal amount of the 2026 Convertible Notes to be converted and pay or deliver, as the case may be, cash, shares of Common Stock, or a combination of cash and shares of Common Stock, at CenterPoint Energy’s election, in respect of the remainder, if any, of CenterPoint Energy’s conversion obligation in excess of the aggregate principal amount of the 2026 Convertible Notes being converted. The conversion rate for the 2026 Convertible Notes is initially 27.1278 shares of Common Stock per \$1,000 principal amount of 2026 Convertible Notes (equivalent to an initial conversion price of approximately \$36.86 per share of Common Stock). The initial conversion price of the 2026 Convertible Notes represents a premium of approximately 25.0% over the last reported sale price of the Common Stock on the NYSE on August 1, 2023. Initially, a maximum of 33,909,700 shares of Common Stock may be issued upon conversion of the 2026 Convertible Notes based on the initial maximum conversion rate of 33.9097 shares of Common Stock per \$1,000 principal amount of 2026 Convertible Notes. The conversion rate will be subject to adjustment in some events (as described in the 2026 Convertible Notes Indenture) but will not be adjusted for any accrued and unpaid interest.

2028 Convertible Senior Notes. Interest on the 2028 Convertible Notes is payable semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2026. The 2028 Convertible Notes will mature on August 1, 2028, unless earlier converted or repurchased by CenterPoint Energy in accordance with their terms.

Prior to the close of business on the business day immediately preceding May 1, 2028, the 2028 Convertible Notes are convertible only under certain conditions. On or after May 1, 2028 until the close of business on the second scheduled trading day immediately preceding the maturity date, holders of the 2028 Convertible Notes may convert all or any portion of their

2028 Convertible Notes at any time at the conversion rate then in effect, irrespective of the conditions. CenterPoint Energy may not redeem the 2028 Convertible Notes prior to the maturity date.

Upon conversion of the 2028 Convertible Notes, CenterPoint Energy will pay cash up to the aggregate principal amount of the 2028 Convertible Notes to be converted and pay or deliver, as the case may be, cash, shares of Common Stock, or a combination of cash and shares of Common Stock, at CenterPoint Energy's election, in respect of the remainder, if any, of CenterPoint Energy's conversion obligation in excess of the aggregate principal amount of the 2028 Convertible Notes being converted. The conversion rate for the 2028 Convertible Notes is initially 21.4477 shares of Common Stock per \$1,000 principal amount of 2028 Convertible Notes (equivalent to an initial conversion price of approximately \$46.63 per share of Common Stock). The initial conversion price of the 2028 Convertible Notes represents a premium of approximately 25.0% over the last reported sale price of the Common Stock on the NYSE on July 28, 2025. Initially, a maximum of 26,809,600 shares of Common Stock may be issued upon conversion of the 2028 Convertible Notes based on the initial maximum conversion rate of 26.8096 shares of Common Stock per \$1,000 principal amount of 2028 Convertible Notes. The conversion rate will be subject to adjustment in some events (as described in the 2028 Convertible Notes Indenture) but will not be adjusted for any accrued and unpaid interest.

In addition, following certain corporate events that occur prior to the maturity date of the convertible notes, CenterPoint Energy will, in certain circumstances, increase the conversion rate for a holder of convertible notes who elects to convert its convertible notes in connection with such a corporate event. If CenterPoint Energy undergoes a fundamental change (as defined in the respective convertible notes indenture), holders of the convertible notes may require CenterPoint Energy to repurchase for cash all or any portion of their convertible notes at a fundamental change repurchase price equal to 100% of the principal amount of the convertible notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

The convertible notes are senior unsecured obligations of CenterPoint Energy and rank senior in right of payment to any of CenterPoint Energy's indebtedness that is expressly subordinated in right of payment to the convertible notes; equal in right of payment to any of CenterPoint Energy's unsecured indebtedness that is not so subordinated; effectively junior in right of payment to any of CenterPoint Energy's secured indebtedness it may incur in the future to the extent of the value of the assets securing such future secured indebtedness; and structurally junior to all indebtedness and other liabilities (including trade payables but excluding intercompany obligations and liabilities of a type not required to be reflected on a balance sheet of such subsidiaries in accordance with GAAP) of CenterPoint Energy's subsidiaries.

Debt Repurchases and Repayments. During 2025, the following debt instruments were repurchased prior to maturity or repaid at maturity:

Registrant	Repurchase/Repayment Date	Debt Instrument	Aggregate Principal (in millions)	Interest Rate	Maturity Date
CERC (1)	March 2025	Term Loan	\$ 10	6.36%	2028
CERC (2)	April 2025	Senior Notes	415	4.10% - 5.40%	2033 - 2047
CERC (3)	June 2025	Term Loan	10	6.53%	2025
		Total CERC	435		
Houston Electric (4)	October 2025	General Mortgage Bonds	234	4.25% - 4.50%	2044 - 2049
		Total Houston Electric	234		
CenterPoint Energy (2)	April 2025	Senior Notes	634	3.70% - 5.40%	2026 - 2049
CenterPoint Energy (5)	July 2025	First Mortgage Bonds	41	3.45%	2025
CenterPoint Energy (4)	October 2025	Senior Notes	329	2.65% - 3.70%	2030 - 2049
		Total CenterPoint Energy	\$ 1,673		

- (1) In March 2025, CERC, through its wholly-owned subsidiary Indiana Gas, repurchased \$10 million aggregate principal amount of Indiana Gas's 6.36% Medium Term Notes, Series F, due 2028 at a redemption price equal to 104.8% of the principal amount of the notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.
- (2) In April 2025, CenterPoint Energy commenced cash tender offers for up to (i) \$600 million aggregate purchase price of certain of CenterPoint Energy's outstanding senior notes, ranging from 2.65% to 5.40%, due 2026 to 2049, and (ii)

\$400 million aggregate purchase price of certain of CERC's senior notes, ranging from 4.10% to 5.40%, due 2028 to 2047. In May 2025, CenterPoint Energy accepted for purchase and paid approximately \$1 billion in connection with the settlement of the tender offers. Upon completion of the tender offers, CenterPoint Energy cancelled approximately \$634 million aggregate principal amount of its senior notes and CERC Corp. cancelled approximately \$415 million aggregate principal amount of its senior notes pursuant to the terms of the respective indentures governing such notes. CenterPoint Energy and CERC recognized a gain on early extinguishment of debt of approximately \$36 million and \$9 million, respectively, which is included in Interest expense and other finance charges on their Statements of Consolidated Income.

- (3) In June 2025, CERC, through its wholly-owned subsidiary Indiana Gas, repaid at maturity \$10 million aggregate principal amount of Indiana Gas's 6.53% Medium Term Notes, Series E due 2025 at a redemption price equal to 100% of the principal amount to be redeemed plus accrued and unpaid interest thereon.
- (4) In September 2025, CenterPoint Energy commenced cash tender offers for up to (i) \$300 million aggregate purchase price of certain of CenterPoint Energy's outstanding senior notes, ranging from 2.65% to 3.70%, due 2030 to 2049, and (ii) \$200 million aggregate purchase price of certain of Houston Electric's general mortgage bonds, ranging from 4.25% to 4.50%, due 2044 to 2049. In October 2025, CenterPoint Energy accepted for purchase and paid approximately \$504 million in connection with the settlement of the tender offers. Upon completion of the tender offers, CenterPoint Energy cancelled approximately \$329 million aggregate principal amount of its senior notes and Houston Electric cancelled approximately \$234 million aggregate principal amount of its general mortgage bonds pursuant to the terms of the respective indentures governing such securities. CenterPoint Energy and Houston Electric recognized a gain on early extinguishment of debt of approximately \$25 million and \$24 million, respectively, which is included in Interest expense and other finance charges on their Statements of Consolidated Income, except to the extent it was deferred as outlined in the table below.
- (5) In July 2025, CenterPoint Energy, through its wholly-owned subsidiary SIGECO, repaid at maturity \$41 million aggregate principal amount of SIGECO's outstanding 3.45% first mortgage bonds due 2025 at a redemption price equal to 100% of the principal amount of the first mortgage bonds to be redeemed plus accrued and unpaid interest thereon.

CenterPoint Energy, Houston Electric and CERC recorded the following gain (loss) on early extinguishment of debt, including make-whole premiums and recognition of deferred debt related costs, in Interest expense and other finance charges on their respective Statements of Consolidated Income unless specified otherwise for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
CenterPoint Energy (1)	\$ 61	\$ —	\$ (11)
Houston Electric (2)	24	—	—
CERC	9	—	—

- (1) The loss on early extinguishment of debt at CenterPoint Energy during 2023 was recorded as a regulatory asset.
- (2) The gain on early extinguishment of debt at Houston Electric during 2025 was recorded as a reduction within Regulatory assets on its Consolidated Balance Sheet.

Securitization Bonds. As of December 31, 2025, CenterPoint Energy, Houston Electric and SIGECO had VIEs including the Bond Companies and the SIGECO Securitization Subsidiary, which are consolidated. The consolidated VIEs are wholly-owned, bankruptcy-remote, special purpose entities that were formed solely for the purpose of securitizing transition property or system restoration property or facilitating the securitization financing of qualified costs. The Securitization Bonds issued by Transition Bond Company IV and Restoration Bond Company II are payable only through the imposition and collection of transition charges or system restoration charges, as defined in the Texas Public Utility Regulatory Act, which are irrevocable, non-bypassable charges to provide recovery of authorized qualified costs. The SIGECO Securitization Bonds are payable only through the imposition of securitization charges payable by SIGECO's retail electric customers, which are non-bypassable charges to provide recovery of the qualified costs of SIGECO authorized by the IURC order. CenterPoint Energy, Houston Electric and SIGECO have no payment obligations in respect of the Securitization Bonds issued by the Bond Companies or the SIGECO Securitization Subsidiary other than to remit the applicable transition, system restoration or securitization charges they collect as set forth in servicing agreements among Houston Electric, the Bond Companies, SIGECO, the SIGECO Securitization Subsidiary and other parties, as applicable. Each special purpose entity is the sole owner of the right to impose, collect and receive the applicable transition, system restoration and securitization charges securing the bonds issued by that entity. Creditors of CenterPoint Energy, Houston Electric and SIGECO have no recourse to any assets or revenues of the Bond

Companies (including the transition, system restoration or securitization charges) or the SIGECO Securitization Subsidiary, as applicable, and the bondholders have no recourse to the general credit of CenterPoint Energy, Houston Electric or SIGECO.

Credit Facilities. The Registrants had the following revolving credit facilities as of December 31, 2025:

Registrant	Execution Date	Size of Facility (in millions)	Draw Rate of SOFR plus (1)	Financial Covenant Limit on Debt for Borrowed Money to Capital Ratio	Debt for Borrowed Money to Capital Ratio as of December 31, 2025 (2)	Termination Date (5)	
CenterPoint Energy	December 6, 2022	\$ 2,400	1.500%	65%	(3)	59.6%	December 6, 2028
CenterPoint Energy (4)	December 6, 2022	250	1.125%	65%		45.0%	December 6, 2028
Houston Electric	December 6, 2022	300	1.250%	67.5%	(3)	54.6%	December 6, 2028
CERC	December 6, 2022	1,050	1.125%	65%		40.8%	December 6, 2028
Total		\$ 4,000					

- (1) Based on credit ratings as of December 31, 2025.
- (2) As defined in the revolving credit facility agreement, excluding Securitization Bonds.
- (3) For CenterPoint Energy and Houston Electric, the financial covenant limit will temporarily increase to 70% if Houston Electric experiences damage from a natural disaster in its service territory and CenterPoint Energy certifies to the administrative agent that Houston Electric has incurred system restoration costs reasonably likely to exceed \$100 million in a consecutive 12-month period, all or part of which Houston Electric intends to seek to recover through securitization financing. Such temporary increase in the financial covenant would be in effect from the date CenterPoint Energy delivers its certification until the earliest to occur of (i) the completion of the securitization financing, (ii) the first anniversary of CenterPoint Energy's certification, or (iii) the revocation of such certification.
- (4) This credit facility was issued by SIGECO.
- (5) On January 29, 2025, CenterPoint Energy, Houston Electric, CERC and SIGECO each entered into Extension Agreements to, among other things, extend the maturity date of the lenders' commitments under each of their respective Credit Agreements by one year, from December 6, 2027 to December 6, 2028.

The Registrants, as well as the subsidiaries of CenterPoint Energy discussed above, were in compliance with all financial debt covenants as of December 31, 2025.

For the periods presented, the Registrants had the following revolving credit facilities and utilization of such facilities:

Registrant	December 31, 2025					December 31, 2024				
	Size of Facility	Loans	Letters of Credit	Commercial Paper	Weighted Average Interest Rate	Size of Facility	Loans	Letters of Credit	Commercial Paper	Weighted Average Interest Rate
	(in millions, except weighted average interest rate)									
CenterPoint Energy (1)	\$ 2,400	\$ —	\$ —	\$ 420	3.78 %	\$ 2,400	\$ —	\$ —	\$ 382	4.59 %
CenterPoint Energy (2)	250	—	—	—	— %	250	—	—	—	— %
Houston Electric	300	—	—	—	— %	300	—	—	—	— %
CERC	1,050	—	—	559	3.86 %	1,050	—	—	599	4.62 %
Total	\$ 4,000	\$ —	\$ —	\$ 979		\$ 4,000	\$ —	\$ —	\$ 981	

- (1) CenterPoint Energy's and CERC's outstanding commercial paper generally have maturities up to 60 days and 30 days, respectively, and are backstopped by the respective issuer's long-term revolving credit facility.
- (2) This credit facility was issued by SIGECO.

Maturities. As of December 31, 2025, maturities of long-term debt through 2030, excluding the ZENS obligation and unamortized discounts, premiums and issuance costs, were as follows:

	CenterPoint Energy (1)	Houston Electric (1)	CERC	Securitization Bonds
	(in millions)			
2026	\$ 2,417	\$ 827	\$ 60	\$ 40
2027	363	323	26	37
2028	3,980	524	1,779	39
2029	911	25	30	41
2030	1,512	526	500	43

(1) These maturities include Securitization Bonds principal repayments on scheduled payment dates.

Liens. As of December 31, 2025, Houston Electric's assets were subject to liens securing approximately \$9.3 billion of general mortgage bonds outstanding under the General Mortgage, including approximately \$68 million held in trust to secure pollution control bonds that mature in 2028 for which CenterPoint Energy is obligated. The general mortgage bonds that are held in trust to secure pollution control bonds are not reflected in Houston Electric's consolidated financial statements because of the contingent nature of the obligations. Houston Electric may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. As of December 31, 2025, approximately \$5.1 billion of additional general mortgage bonds could be issued on the basis of retired bonds and 70% of property additions. No first mortgage bonds are outstanding under the M&DOT, and Houston Electric is contractually obligated to not issue any additional first mortgage bonds under the M&DOT and is undertaking actions to release the lien of the M&DOT and terminate the M&DOT.

As of December 31, 2025, SIGECO had approximately \$1.5 billion aggregate principal amount of first mortgage bonds outstanding. Generally, all of SIGECO's real and tangible property is subject to the lien of SIGECO's mortgage indenture which was amended and restated effective as of January 1, 2023. As of December 31, 2025, SIGECO was permitted to issue additional bonds under its mortgage indenture up to 70% of then currently unfunded property additions and approximately \$892 million of additional first mortgage bonds could be issued on this basis.

Houston Electric and CERC participate in a money pool through which they can borrow or invest on a short-term basis. For additional information, see Note 18.

(13) Income Taxes

The components of the Registrants' income tax expense (benefit) were as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
CenterPoint Energy			
Current income tax expense (benefit):			
Federal	\$ 64	\$ (17)	\$ 106
State	9	(9)	33
Total current income tax expense (benefit)	73	(26)	139
Deferred income tax expense (benefit):			
Federal	174	218	119
State	(52)	3	(88)
Total deferred income tax expense	122	221	31
Total income tax expense	\$ 195	\$ 195	\$ 170

Year Ended December 31,		
2025	2024	2023
(in millions)		

Houston Electric

Current income tax expense (benefit):			
Federal	\$ 47	\$ 62	\$ (26)
State	19	15	34
Total current income tax expense	<u>66</u>	<u>77</u>	<u>8</u>
Deferred income tax expense:			
Federal	80	60	159
State	1	1	1
Total deferred income tax expense	<u>81</u>	<u>61</u>	<u>160</u>
Total income tax expense	<u>\$ 147</u>	<u>\$ 138</u>	<u>\$ 168</u>

CERC

Current income tax expense (benefit):			
Federal	\$ 88	\$ 55	\$ 12
State	1	(6)	3
Total current income tax expense	<u>89</u>	<u>49</u>	<u>15</u>
Deferred income tax expense (benefit):			
Federal	70	60	95
State	(62)	(5)	(136)
Total deferred income tax expense (benefit)	<u>8</u>	<u>55</u>	<u>(41)</u>
Total income tax expense (benefit)	<u>\$ 97</u>	<u>\$ 104</u>	<u>\$ (26)</u>

A reconciliation of income tax expense (benefit) using the federal statutory income tax rate to the actual income tax expense and resulting effective income tax rate were as follows for the periods presented:

	Year Ended December 31,					
	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
(in millions, except percentages)						
CenterPoint Energy (1) (2) (3) (4)						
Income before income taxes	\$ 1,247		\$ 1,214		\$ 1,087	
Federal statutory income tax rate	262	21 %	255	21 %	228	21 %
Increase (decrease) in tax expense resulting from:						
State income tax benefit, net of federal income tax	(30)	(2)%	(8)	(1)%	(44)	(4)%
Tax credits	(5)	— %	(9)	(1)%	(6)	(1)%
Nontaxable or non-deductible items:						
Goodwill	46	4 %	—	— %	—	— %
Equity AFUDC	(13)	(1)%	(12)	(1)%	(13)	(1)%
Other	3	— %	(1)	— %	10	1 %
Changes in unrecognized tax benefits	(8)	(1)%	3	— %	1	— %
Excess deferred income tax amortization	(63)	(5)%	(43)	(4)%	(44)	(4)%
Sale of Energy Systems Group	—	— %	—	— %	28	3 %
Other, net	3	— %	10	2 %	10	1 %
Total	(67)	(5)%	(60)	(5)%	(58)	(5)%
Total income tax expense and effective tax rate	\$ 195	16 %	\$ 195	16 %	\$ 170	16 %
Houston Electric (5)						
Income before income taxes	\$ 725		\$ 684		\$ 761	
Federal statutory income tax rate	152	21 %	144	21 %	160	21 %
Increase (decrease) in tax expense resulting from:						
State income tax expense, net of federal income tax	15	2 %	12	2 %	27	4 %
Tax credits	—	— %	(3)	— %	(2)	(1)%
Nontaxable or non-deductible items:						
Equity AFUDC	(6)	(1)%	(5)	(1)%	—	— %
Other	1	— %	(2)	— %	—	— %
Excess deferred income tax amortization	(17)	(2)%	(17)	(2)%	(17)	(2)%
Other, net	2	— %	9	— %	—	— %
Total	(5)	(1)%	(6)	(1)%	8	1 %
Total income tax expense and effective tax rate	\$ 147	20 %	\$ 138	20 %	\$ 168	22 %
CERC (1) (6) (7) (8)						
Income before income taxes	\$ 736		\$ 644		\$ 486	
Federal statutory income tax rate	155	21 %	135	21 %	102	21 %
Increase (decrease) in tax expense resulting from:						
State income tax benefit, net of federal income tax	(48)	(7)%	(10)	(2)%	(106)	(22)%
Tax credits	—	— %	(1)	— %	—	— %
Nontaxable or non-deductible items:						
Goodwill	26	4 %	—	— %	—	— %
Equity AFUDC	(3)	— %	(4)	(1)%	—	— %
Other	—	— %	(3)	— %	5	1 %
Changes in unrecognized tax benefits	1	— %	1	— %	1	— %
Excess deferred income tax amortization	(36)	(5)%	(15)	(2)%	(23)	(5)%
Other, net	2	— %	1	— %	(5)	— %
Total	(58)	(8)%	(31)	(5)%	(128)	(26)%
Total income tax expense (benefit) and effective tax rate	\$ 97	13 %	\$ 104	16 %	\$ (26)	(5)%

(1) For all periods presented, Minnesota contributed to the majority (greater than 50%) of the tax effect.

(2) For 2025, included in the state income tax benefit above is a \$74 million net benefit from the remeasurement of deferred state income taxes, resulting from apportionment changes.

(3) For 2024, included in the state income tax benefit above is a \$47 million benefit from the remeasurement of deferred state income taxes, resulting from state apportionment changes and a Louisiana statutory rate change. In addition, a

\$17 million valuation allowance was established against Louisiana and Mississippi NOLs, since those NOLs will not be utilized due to the Louisiana and Mississippi natural gas LDC businesses sale.

- (4) For 2023, included in the state income tax benefit is a \$69 million benefit for the impact of state apportionment changes that resulted in the remeasurement of state deferred taxes of the unitary group.
- (5) For all periods presented, Texas contributed to 100% of the tax effect.
- (6) For 2025, included in the state income tax benefit above is a \$73 million net benefit from state apportionment changes, resulting in a remeasurement of state deferred taxes.
- (7) For 2024, included in the state income tax benefit above is a \$45 million benefit resulting from a remeasurement of state deferred taxes due to state apportionment changes and a Louisiana statutory rate change. In addition, a \$17 million valuation allowance was established against Louisiana and Mississippi NOLs, since those NOLs will not be utilized due to the Louisiana and Mississippi natural gas LDC businesses sale.
- (8) For 2023, included in the state income tax benefit above is a \$66 million benefit for the impact of state apportionment changes that resulted in the remeasurement of state deferred taxes of the unitary group.

The tax effects of temporary differences that gave rise to significant portions of deferred tax assets and liabilities were as follows for the periods presented:

	December 31, 2025	December 31, 2024
	(in millions)	
CenterPoint Energy		
Deferred tax assets:		
Benefits and compensation	\$ 97	\$ 126
Regulatory liabilities	325	348
Loss and credit carryforwards	1,012	942
Asset retirement obligations	81	98
Other	235	150
Valuation allowance	(37)	(35)
Total deferred tax assets	1,713	1,629
Deferred tax liabilities:		
Property, plant and equipment	4,609	4,384
Regulatory assets	734	750
Investment in ZENS and equity securities related to ZENS	950	866
Other	22	18
Total deferred tax liabilities	6,315	6,018
Net deferred tax liabilities	\$ 4,602	\$ 4,389
Houston Electric		
Deferred tax assets:		
Benefits and compensation	\$ 6	\$ 8
Regulatory liabilities	163	158
Loss and credit carryforwards	493	408
Asset retirement obligations	9	9
Other	20	16
Total deferred tax assets	691	599
Deferred tax liabilities:		
Property, plant and equipment	2,161	1,988
Regulatory assets	139	113
Total deferred tax liabilities	2,300	2,101
Net deferred tax liabilities	\$ 1,609	\$ 1,502
CERC		
Deferred tax assets:		
Benefits and compensation	\$ 14	\$ 17
Regulatory liabilities	127	150
Loss and credit carryforwards	564	694
Asset retirement obligations	59	82
Other	196	122
Valuation allowance	(28)	(25)
Total deferred tax assets	932	1,040
Deferred tax liabilities:		
Property, plant and equipment	1,871	1,883
Regulatory assets	467	513
Other	20	14
Total deferred tax liabilities	2,358	2,410
Net deferred tax liabilities	\$ 1,426	\$ 1,370

Tax Attribute Carryforwards and Valuation Allowance. As of December 31, 2025, CenterPoint Energy had (i) federal NOL carryforwards of \$3.3 billion, which have an indefinite carryforward period; (ii) federal charitable contribution carryforwards of \$63 million, which expire beginning in 2028; (iii) federal corporate alternative minimum tax carryforwards of \$201 million, which have an indefinite carryforward period; (iv) \$2 billion of gross state NOL carryforwards, which expire beginning in 2029; and (v) \$1 million of state tax credits, net of valuation allowance, which expire beginning in 2032.

CenterPoint Energy reported a valuation allowance against certain state NOL and credit carryforwards because it is more likely than not that the benefit will not be realized.

As of December 31, 2025, Houston Electric had (i) federal NOL carryforwards of \$1.9 billion, which have an indefinite carryforward period; and (ii) federal corporate alternative minimum tax carryforwards of \$96 million, which have an indefinite carryforward period.

As of December 31, 2025, CERC had (i) federal NOL carryforwards of \$1.5 billion, which have an indefinite carryforward period; (ii) federal corporate alternative minimum tax carryforwards of \$152 million, which have an indefinite carryforward period; and (iii) \$927 million of gross state NOL carryforwards, which expire beginning in 2029.

A reconciliation of CenterPoint Energy's beginning and ending balance of unrecognized tax benefits, excluding interest and penalties, are as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Balance, beginning of year	\$ 25	\$ 25	\$ 26
Lapse of statute of limitations	(8)	—	(1)
Balance, end of year	<u>\$ 17</u>	<u>\$ 25</u>	<u>\$ 25</u>

As of December 31, 2025, CenterPoint Energy reported net unrecognized tax benefits, including penalties and interest, of \$24 million, which were included in Other non-current liabilities in the Consolidated Balance Sheets. Included in the balance of uncertain tax positions as of December 31, 2025 were \$17 million of tax benefits that, if recognized, would affect the effective tax rate. The Registrants recognize interest accrued related to unrecognized tax benefits and penalties as income tax expense. The above table does not include \$7 million of accrued penalties and interest as of December 31, 2025.

Tax Audits and Settlements. Tax years through 2022 have been audited and settled with the IRS for CenterPoint Energy. For tax years 2023, 2024 and 2025, the Registrants are participants in the IRS's Compliance Assurance Process.

Income Taxes Payments and Refunds. For income taxes paid or refunds received for the years ended December 31, 2025, 2024 and 2023, see Note 17.

(14) Commitments and Contingencies

(a) Purchase Obligations (CenterPoint Energy and CERC)

Commitments include minimum purchase obligations related to CenterPoint Energy's and CERC's Natural Gas reportable segment and CenterPoint Energy's Electric reportable segment. Contracts with minimum payment obligations have various quantity requirements and durations and are not classified as non-trading derivative assets and liabilities in CenterPoint Energy's and CERC's Consolidated Balance Sheets as of December 31, 2025 and 2024 because these contracts meet an exception as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include transportation contracts that do not meet the definition of a derivative.

As of December 31, 2025, CenterPoint Energy and CERC had the following undiscounted minimum purchase obligations:

	CenterPoint Energy			CERC	
	Natural Gas Supply	Electric Supply (1)	Other (2)	Natural Gas Supply	
		(in millions)			
2026	\$ 689	\$ 131	\$ 158	\$ 684	
2027	591	157	198	587	
2028	546	98	137	542	
2029	526	96	8	522	
2030	484	80	117	480	
Thereafter	1,344	1,574	1	1,322	
Total	\$ 4,180	\$ 2,136	\$ 619	\$ 4,137	

- (1) Primarily related to PPAs with commitments ranging from 20 years to 27 years.
(2) Primarily related to technology hardware and software agreements.

Excluded from the table above are estimates for cash outlays from other PPAs through Indiana Electric that do not have minimum thresholds but require payment when energy is generated by the provider. Costs arising from certain of these commitments are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

(b) Guarantees (CenterPoint Energy)

CenterPoint Energy recognizes guarantee obligations at fair value. CenterPoint Energy discloses parent company guarantees of a subsidiary's obligation when that guarantee results in the exposure of a material obligation of the parent company even if the probability of fulfilling such obligation is considered remote.

On May 21, 2023, CenterPoint Energy, through Vectren Energy Services, entered into the Equity Purchase Agreement to sell Energy Systems Group. The sale closed on June 30, 2023. See Note 4 for further information.

In the normal course of business prior to the consummation of the transaction on June 30, 2023, CenterPoint Energy, primarily through Vectren, issued parent company level guarantees supporting Energy Systems Group's obligations. When Energy Systems Group was wholly-owned by CenterPoint Energy, these guarantees did not represent incremental consolidated obligations, but rather, these guarantees represented guarantees of Energy Systems Group's obligations to allow it to conduct business without posting other forms of assurance. For those obligations where potential exposure can be estimated, management estimated the maximum exposure under these guarantees to be approximately \$434 million as of December 31, 2025 and expects the exposure to decrease pro rata. This exposure primarily relates to energy savings guarantees on federal energy savings performance contracts. Other parent company level guarantees, certain of which do not contain a cap on potential liability, were issued prior to the sale of Energy Systems Group in support of federal operations and maintenance projects for which a maximum exposure cannot be estimated based on the nature of the projects.

Under the terms of the Equity Purchase Agreement, ESG Holdings Group must generally use reasonable best efforts to replace existing CenterPoint Energy guarantees with credit support provided by a party other than CenterPoint Energy as of and after the closing of the transaction. The Equity Purchase Agreement also requires certain protections to be provided for any damages incurred by CenterPoint Energy in relation to these guarantees not released by closing. No additional guarantees were provided by CenterPoint Energy in favor of Energy Systems Group subsequent to the closing of the sale on June 30, 2023.

While there can be no assurance that performance under any of these parent company guarantees will not be required in the future, CenterPoint Energy considers the likelihood of a material amount being incurred to be remote. CenterPoint Energy believes that, from Energy Systems Group's inception in 1994 to the closing of the sale of Energy Systems Group on June 30, 2023, Energy Systems Group had a history of generally meeting its performance obligations and energy savings guarantees and its installed products operated effectively. CenterPoint Energy recorded no amounts on its Consolidated Balance Sheets as of December 31, 2025 and 2024 related to its obligation under the outstanding guarantees.

(c) Legal, Environmental and Other Matters

Legal Matters

Litigation Related to Hurricane Beryl. Various federal, state and local governmental and regulatory agencies and other entities called for or conducted inquiries and investigations into Hurricane Beryl, the efforts made by Houston Electric to prepare for, and respond to, this event, including the electric service outage issues, and the procurement of TEEEF. Moreover, additional governmental and regulatory agencies and other entities may conduct such inquiries and investigations. Ongoing and future inquiries, investigations and proposed legislation regarding Hurricane Beryl could adversely affect our business, financial condition, results of operations and cash flows, including with respect to our recovery of costs incurred as a result of Hurricane Beryl or future severe weather events; the assessment of financial penalties; changes to Houston Electric's system, service territories, operations and/or regulatory treatment; and the viability for Houston Electric to continue leasing TEEEF. Further, on January 22, 2025, a putative shareholder of CenterPoint Energy, Donel Davidson, filed a derivative petition in Harris County District Court, Texas, alleging breach of fiduciary duty and unjust enrichment on behalf of CenterPoint Energy against certain of its current and former directors and officers citing, in part, the topics of these inquiries and investigations. The action seeks to recover damages and other relief from the defendants on behalf of CenterPoint Energy. The action was removed to the Texas Business Courts, and on June 18, 2025, the parties filed an agreed upon stipulation to stay the case, which was approved by the court on June 24, 2025. As of December 31, 2025, the case remains stayed. Additionally, on February 12, 2025, a second putative shareholder of CenterPoint Energy made a demand on the Board to investigate the same basic allegations raised in the derivative petition filed by Donel Davidson.

CenterPoint Energy, CenterPoint Energy Service Company, LLC and Houston Electric are subject to current and potential future litigation and claims arising out of Hurricane Beryl, which litigation and claims could include allegations of, among other things, personal injury, wrongful death, property damage, various economic losses in connection with loss of power, unlawful business practices, and others. Following Hurricane Beryl, several putative class actions were filed against CenterPoint Energy and/or Houston Electric in the District Courts of Harris County, Texas, on behalf of individuals or entities who claim losses due to power outages lasting at least 48 hours as a result of Hurricane Beryl, such actions consisting of the following proposed classes: (1) all restaurants in Harris County, Galveston County, and Montgomery County; (2) all residential customers; and (3) all health, wellness, medical and beauty facilities in Harris County. These putative classes asserted claims and theories of negligence, gross negligence, nuisance, fraud, and/or violation of Houston Electric's tariff for retail delivery service, and each seeks damages in excess of \$100 million for, among other things, business interruption, property damage and loss, cost of repair, loss of use and market value, lost income, nuisance, extreme mental anguish and/or punitive damages. On July 30, 2025, the plaintiffs in the putative class action on behalf of all residential customers nonsuited without prejudice all claims and causes of action. In addition, the plaintiffs in the other two putative class actions have amended their petitions to remove all class action allegations and assert claims of negligence, gross negligence, nuisance and/or intentional misconduct. One of those lawsuits is brought by approximately 220 individually named plaintiffs, and the other lawsuit includes approximately 50 individually named plaintiffs. Several individual actions have also been filed in Harris County District Courts asserting claims of negligence, negligence per se, negligent undertaking and/or gross negligence against CenterPoint Energy, CenterPoint Energy Service Company, LLC and/or Houston Electric. Certain plaintiffs in these actions allege personal injury or property damage and seek damages in excess of \$1 million. These cases have been transferred to the designated MDL pretrial court. CenterPoint Energy, CenterPoint Energy Service Company, LLC and/or Houston Electric filed dispositive motions in the two former putative class action cases and certain of the individual actions. On December 1, 2025, the MDL pretrial court granted Houston Electric's dispositive motion in one of the individual actions brought by a business alleging losses due to a power outage following Hurricane Beryl. On January 28, 2026, the MDL pretrial court denied dispositive motions filed by CenterPoint Energy, CenterPoint Energy Service Company, LLC and/or Houston Electric in individual actions alleging personal injury or property damage. Houston Electric filed notices of appeal of these orders. The remaining dispositive motions that have been filed are set for hearing by the MDL pretrial court on February 23, 2026. CenterPoint Energy, CenterPoint Energy Service Company, LLC and Houston Electric intend to vigorously defend themselves against the lawsuits. CenterPoint Energy and its subsidiaries have general and excess liability insurance policies that provide coverage for third party bodily injury and property damage claims. Given the nature of some allegations, certain insurers have disputed, and more insurers may dispute, coverage for some types of claims or damages that have been or may in the future be alleged by plaintiffs. For example, CenterPoint Energy has received from two insurers denials of indemnity coverage in the cases arising out of power outages based on the failure to supply exclusion, and those insurers have also reserved their rights with respect to coverage in those actions. CenterPoint Energy, CenterPoint Energy Service Company, LLC and Houston Electric intend to continue to pursue all available insurance coverage for all of these matters. To date, there have not been demands, quantification, disclosure or discovery of damages by any party to any of the above legal matters that are sufficient to enable CenterPoint Energy and its subsidiaries to estimate exposure. Given that, as well as the preliminary nature of the proceedings, the number of parties and complexity of issues involved, and the uncertainties of litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or

consequences of any of the foregoing matters or to estimate a range of potential losses. For more information regarding Hurricane Beryl, see Note 7.

Litigation Related to the February 2021 Winter Storm Event. Various legal proceedings are still pending against numerous entities with respect to the February 2021 Winter Storm Event, including against CenterPoint Energy, Utility Holding, Houston Electric, and CERC. Like other Texas energy companies and TDUs, CenterPoint Energy and Houston Electric have become involved in certain investigations, litigation and other regulatory and legal proceedings regarding their efforts to restore power during the storm and their compliance with NERC, ERCOT and PUCT rules and directives. Additionally, like other natural gas market participants, CERC has been named in litigation alleging gas market manipulation.

CenterPoint Energy, Utility Holding and Houston Electric, along with hundreds of other defendants (including ERCOT, power generation companies, other TDUs, natural gas producers, REPs, and other entities) received claims and lawsuits filed by plaintiffs alleging wrongful death, personal injury, property damage and other injuries and damages. As of December 31, 2025, there were approximately 220 pending lawsuits that are consolidated in Texas state court in Harris County, Texas, as part of the MDL proceeding related to the February 2021 Winter Storm Event, and CenterPoint Energy and Houston Electric, along with numerous other entities, have been named as defendants in approximately 150 of those lawsuits. The plaintiffs in the lawsuits asserted negligence, gross negligence and nuisance causes of action, among others, against CenterPoint Energy, Utility Holding and Houston Electric. Following the filing of dispositive motions under Rule 91a of the Texas Rules of Civil Procedure in five representative or “bellwether” cases in the MDL proceeding and related mandamus proceedings in the court of appeals and the Supreme Court of Texas, the plaintiffs’ claims against CenterPoint Energy and Houston Electric have been dismissed with the exception of the plaintiffs’ gross negligence claims. With respect to the plaintiffs’ gross negligence claims, the Supreme Court of Texas concluded that the plaintiffs should be given the opportunity to replead those claims. Following issuance of the decision of the Supreme Court of Texas on September 11, 2025, the MDL judge issued an order with a January 9, 2026 deadline for the plaintiffs to replead their gross negligence claims and a schedule for the TDUs to file certain dispositive motions in response. As of the date of filing this Form 10-K, most of the plaintiffs have filed amended petitions. The claims against Utility Holding have been dismissed in light of the judge’s initial rulings on the Rule 91a dispositive motions. The TDUs (including Houston Electric) also filed a motion to dismiss under Chapter 150 of the Texas Civil Practice and Remedies Code in one of the bellwether cases and argued that all of plaintiffs’ claims should be dismissed because the plaintiffs did not include a sufficient certificate of merit by a qualified engineer with their petition, as required by Texas law. On November 13, 2024, the MDL judge granted the TDUs’ motion to dismiss under Chapter 150, and on December 3, 2024, the plaintiffs filed a notice of appeal of that ruling. Briefing in this appellate proceeding is complete. Aside from the filing of amended pleadings and certain dispositive motions in response, all litigation otherwise remains stayed in the MDL. CenterPoint Energy and Houston Electric intend to vigorously defend themselves against the remaining claims.

In February 2023, multiple lawsuits were filed in state district court in Harris County and Tom Green County, Texas, against dozens of gas market participants in Texas, including natural gas producers, processors, pipelines, marketers, sellers, traders, gas utilities, and financial institutions. Plaintiffs named CERC as a defendant, along with “CenterPoint Energy Services, Inc.,” incorrectly identifying it as CERC’s parent company (CenterPoint Energy previously divested CenterPoint Energy Services, Inc.). There are two main remaining lawsuits—one filed in Harris County and one in Tom Green County—which were brought by an entity that purports to be an assignee of the claims of tens of thousands of persons and entities. These suits generally allege that the defendants engaged in gas market manipulation, including by intentionally withholding, suppressing, or diverting supplies of natural gas in connection with the February 2021 Winter Storm Event. Plaintiffs allege that this manipulation impacted gas supply and prices and caused blackouts and other damage. Plaintiffs assert claims for tortious interference with existing contract, private nuisance, and unjust enrichment. The lawsuits do not specify the amount of damages sought, but seek broad categories of actual, compensatory, consequential economic, and punitive damages; restitution and disgorgement; pre- and post-judgment interest; costs and attorneys’ fees; and other relief. All of these lawsuits have been transferred to the existing MDL proceeding referenced above. These gas market cases are in addition to the 220 cases noted above regarding electric market issues.

CERC has vigorously defended itself against the claims raised in the gas market cases. On February 2, 2024, CERC filed pleas to the jurisdiction in the three cases in which it was served on February 2, 2024 and again on May 17, 2024; CERC also partially joined the other defendants’ motions to dismiss and additional pleas to the jurisdiction. On November 7, 2024 and November 11, 2024, the MDL judge granted defendants’ motion to dismiss and CERC’s plea to the jurisdiction in all three cases. As a result of these rulings, all claims against CERC were dismissed with prejudice. Plaintiffs have appealed these rulings, and the appeals have been assigned to the Court of Appeals for the First District of Texas. One of the three cases against CERC was a putative class action, but that case has been dismissed. On January 17, 2025, the plaintiffs in the putative class action case filed an unopposed motion to dismiss their appeal, which the Court of Appeals granted on February 4, 2025. CERC is still a defendant in two remaining cases. The parties have completed their briefing for the Court of Appeals for the First District of Texas and await a ruling.

To date, there have not been demands, quantification, disclosure or discovery of damages by any party to any of the above legal matters that are sufficient to enable CenterPoint Energy and its subsidiaries to estimate exposure. Given that, as well as the preliminary nature of the proceedings, the number of parties and complexity of issues involved, and the uncertainties of litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or consequences of any of the foregoing matters or to estimate a range of potential losses. CenterPoint Energy and its subsidiaries have general and excess liability insurance policies that provide coverage for third party bodily injury and property damage claims. As CenterPoint Energy previously noted, given the nature of certain of the plaintiffs' allegations, insurance coverage may not be available other than for third party bodily injury and property damage claims caused by an accident, and one of CenterPoint Energy's insurers has reserved its rights with respect to coverage for plaintiffs' claims in the gas market cases. CenterPoint Energy and its subsidiaries intend to continue to pursue all available insurance coverage for all of these matters.

Jefferson Parish. Several parishes and the State of Louisiana filed 42 suits under Louisiana's State and Local Coastal Resources Management Act against hundreds of oil and gas companies seeking compensatory damages for contamination and erosion of the Louisiana coastline allegedly caused by historical oil and gas operations. One of the defendants in one of the lawsuits (filed in 2013 by the Parish of Jefferson) is Primary Fuels, Inc., a predecessor company of CenterPoint Energy, which operated in the oilfield at issue in the case from 1983-1989. All 42 suits were removed to Louisiana federal courts twice and were stayed for several years pending the federal courts' consideration of various motions to remand and multiple appeals of remand orders. Several cases involving other parishes were remanded to Louisiana state court. To date, two of the 42 suits have substantially progressed in state court. The first case, *Cameron Parish v. Auster Oil & Gas, Inc., et al.*, settled shortly before trial on confidential terms. The second case, *Plaquemines Parish v. Rozel Operating Co., et al.*, was tried against one defendant, Chevron Corporation, and on April 4, 2025, the jury returned a verdict of \$744.6 million. Before final judgment was entered, the *Rozel* case was stayed until the United States Supreme Court rules on the merits of a jurisdictional issue in a related case that does not include Primary Fuels, Inc. As of December 31, 2025, the federal district court had not ruled on Jefferson Parish's motion to remand to state court the lawsuit which includes Primary Fuels, Inc. among the defendants. The timing of further progress in the Jefferson Parish case is uncertain and dependent in part on the court's ruling on the motion to remand and further developments in other related cases.

Because of the procedurally preliminary nature of the proceedings in the case in which Primary Fuels, Inc. is a defendant, lack of information about both the scope of and damages for Jefferson Parish's claim against Primary Fuels, Inc., the number of parties and complexity of issues involved, and the uncertainties of litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or consequences of this matter or to estimate a range of potential losses. CenterPoint Energy intends to continue to vigorously defend itself against the claims raised and pursue any and all available insurance coverage.

Environmental Matters

MGP Sites. CenterPoint Energy, CERC and their predecessors, including predecessors of Vectren, operated MGPs in the past. The costs CenterPoint Energy or CERC, as applicable, expect to incur to fulfill their respective obligations are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments and inflation factors, among others. While CenterPoint Energy and CERC have recorded obligations for all costs which are probable and estimable, including amounts they are presently obligated to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen, and those costs may not be subject to PRP or insurance recovery.

- (i) *Minnesota MGPs (CenterPoint Energy and CERC).* With respect to certain Minnesota MGP sites, CenterPoint Energy and CERC have completed state-ordered remediation and continue state-ordered monitoring and water treatment. CenterPoint Energy and CERC recorded a liability as reflected in the table below for continued monitoring and any future remediation required by regulators in Minnesota.
- (ii) *Indiana MGPs (CenterPoint Energy and CERC).* In the Indiana Gas service territory, the existence, location and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which CenterPoint Energy and CERC may have some remedial responsibility. A remedial investigation/feasibility study was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's VRP. CenterPoint Energy has also identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. CenterPoint Energy is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

(iii) *Other MGPs (CenterPoint Energy and CERC)*. In addition to the Minnesota and Indiana sites, the EPA and other regulators have investigated MGP sites that were owned or operated by CenterPoint Energy or CERC or may have been owned by one of their former affiliates.

Total costs that may be incurred in connection with addressing these sites cannot be determined at this time. The estimated accrued costs are limited to CenterPoint Energy's and CERC's share of the remediation efforts and are therefore net of exposures of other PRPs. The estimated range of possible remediation costs for the sites for which CenterPoint Energy and CERC believe they may have responsibility was based on remediation continuing for the minimum time frame given in the table below:

	December 31, 2025	
	CenterPoint Energy	CERC
	(in millions, except years)	
Amount accrued for remediation	\$ 13	\$ 11
Minimum estimated remediation costs	9	7
Maximum estimated remediation costs	48	41
Minimum years of remediation	5	5
Maximum years of remediation	50	50

The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will depend on the number of sites to be remediated, the participation of other PRPs, if any, and the remediation methods used.

CenterPoint Energy and CERC do not expect the ultimate outcome of these matters to have a material adverse effect on the financial condition, results of operations or cash flows of either CenterPoint Energy or CERC.

Asbestos. Some facilities owned by the Registrants or their predecessors contain or have contained asbestos insulation and other asbestos-containing materials. The Registrants are from time to time named, along with numerous others, as defendants in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos, and the Registrants anticipate that additional claims may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, the Registrants do not expect these matters, either individually or in the aggregate, to have a material adverse effect on their financial condition, results of operations or cash flows.

CCR Rule (CenterPoint Energy). In April 2015, the EPA finalized the CCR Rule. The final rule allows beneficial reuse of ash, and a portion of the ash generated by Indiana Electric's generating plants will continue to be reused.

Indiana Electric historically operated three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility. Under the CCR Rule, Indiana Electric is required to perform integrity assessments, including ground water monitoring, at its F.B. Culley and A.B. Brown generating stations. Pursuant to the CCR Rule, both the Culley East and A.B. Brown facilities were taken out of service in a timely manner per the commitments made to the EPA in the extension requests filed for both ponds. On April 24, 2019, Indiana Electric received an order from the IURC approving recovery in rates of costs associated with the closure of the Culley West pond, which has already completed closure activities. On August 14, 2019, Indiana Electric filed its petition with the IURC for recovery of costs associated with the closure of the A.B. Brown ash pond, which would include costs associated with the excavation and recycling of ponded ash. This petition was subsequently approved by the IURC on May 13, 2020. On October 28, 2020, the IURC approved Indiana Electric's ECA proceeding, which included the initiation of recovery of the federally mandated project costs.

On November 1, 2022, Indiana Electric filed for a CPCN to recover federally mandated costs associated with closure of the Culley East Pond, its third and final ash pond. Indiana Electric sought accounting and ratemaking relief for the project, and on June 8, 2023, Indiana Electric filed a revised CPCN for recovery of the federally mandated ash pond costs. On February 7, 2024 the IURC approved the federally mandated costs, both incurred and projected, of \$52 million in capital costs, plus an estimated \$133,000 in annual operation and maintenance expenses, for recovery through the ECA. Following approval of its most recent rate case, this project is now being recovered through base rates.

As of December 31, 2025, CenterPoint Energy had recorded an approximate \$175 million ARO, which represents the discounted value of future cash flow estimates to close the ponds at A.B. Brown and F.B. Culley. This estimate is subject to change due to the contractual arrangements; continued assessments of the ash, closure methods, and the timing of closure; implications of Indiana Electric's generation transition plan; changing environmental regulations; and proceeds received from

the settlements in a previously settled insurance proceedings. In addition to these AROs, Indiana Electric also anticipates equipment purchases of between \$60 million and \$80 million to complete the A.B. Brown closure project.

On April 25, 2024, the EPA released its final Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments rule (CCR Legacy Rule), which was published in the Federal Register in May 2024. The CCR Legacy Rule requires companies to investigate previously closed impoundments that were used historically for ash disposal or locations which have had ash placed on them in amounts set forth in the CCR Legacy Rule. The Registrants have completed their preliminary review of potential sites that will require further investigation under the CCR Legacy Rule and identified certain sites in Indiana for further evaluation. During 2024, Indiana Electric recorded an approximate \$11 million ARO with a corresponding increase of \$11 million to Property, plant and equipment for amounts recoverable for electric generation stations that are currently in service. These estimates reflect the discounted value of future estimated capping costs for an area of historic ash placement at F.B. Culley. Indiana Electric will continue to refine the assumptions, engineering analyses and resulting cost estimates associated with this ARO and such refinement could materially impact the amount of the estimated ARO.

Clean Water Act Permitting and Power Plant Discharges. In 2015, the EPA finalized revisions to the existing steam electric wastewater discharge standards which set more stringent wastewater discharge limits and effectively prohibited further wet disposal of coal ash in ash ponds. In February 2019, the IURC approved Indiana Electric's Effluent Limitation Guidelines Compliance Plan for its F.B. Culley Generating Station, which was completed in compliance with the requirements of the Effluent Limitation Guidelines. On April 25, 2024, the EPA released its final Supplemental Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category. On December 31, 2025, the EPA published a final rule extending various deadlines and other provisions of the 2024 Supplemental Effluent Limitation Guidelines. The Registrants currently anticipate that they will be in compliance with the Supplemental Effluent Limitation Guidelines at the Culley facility due to previous wastewater treatment upgrades.

Other Environmental. From time to time, the Registrants identify the presence of environmental contaminants during operations or on property where their predecessors have conducted operations. Other such sites involving contaminants may be identified in the future. The Registrants have and expect to continue to remediate any identified sites consistent with state and federal legal obligations. From time to time, the Registrants have received notices, and may receive notices in the future, from regulatory authorities or others regarding status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, the Registrants have been, or may be, named from time to time as defendants in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, the Registrants do not expect these matters, either individually or in the aggregate, to have a material adverse effect on their financial condition, results of operations or cash flows.

Other Proceedings

The Registrants are involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. From time to time, the Registrants are also defendants in legal proceedings with respect to claims brought by various plaintiffs against broad groups of participants in the energy industry. Some of these proceedings involve substantial amounts. The Registrants regularly analyze current information and, as necessary, provide accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. The Registrants do not expect the disposition of these matters to have a material adverse effect on the Registrants' financial condition, results of operations or cash flows.

(15) Earnings Per Share (CenterPoint Energy)

Basic earnings per common share is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period. Participating securities are excluded from weighted average number of common shares outstanding in the computation of basic earnings per common share. Diluted earnings per common share is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding, including all potentially dilutive common shares, if the effect of such common shares is dilutive.

Diluted earnings per common share reflects the dilutive effect of potential common shares from share-based awards. The dilutive effect of restricted stock is computed using the if-converted method, which assumes conversion of the restricted stock at the beginning of the period. The dilutive effect of restricted stock is computed using the treasury stock method, as applicable, which includes the incremental shares that would be hypothetically vested in excess of the number of shares assumed to be hypothetically repurchased with the assumed proceeds.

Until settlement of the equity forwards executed in April 2025 and May 2025 as further described in Note 11, dilutive earnings per common share reflects the dilutive impact of potential issuances of shares of Common Stock associated with the outstanding equity forwards. The dilutive effect of equity forwards is determined under the treasury stock method. Share dilution occurs when the average market price of Common Stock is higher than the forward sales price at the end of the reporting period.

Diluted earnings per common share will also reflect the dilutive effect of potential conversions of our convertible notes into shares of Common Stock. Convertible debt in which the principal amount must be settled in cash is excluded from the calculation of diluted earnings per common share. There would be no interest expense adjustment to the numerator for the cash-settled portion of the convertible notes because that portion will always be settled in cash. The conversion spread value in shares will be included in diluted earnings per common share using the if-converted method if the average market price of Common Stock is higher than the conversion price. The denominator of diluted earnings per common share is determined by dividing the conversion spread value of the share-settled portion of the convertible notes as of the reporting date by the average share price over the reporting period. For further details on the convertible notes, see Note 12.

The following table reconciles numerators and denominators of CenterPoint Energy's basic and diluted earnings per common share for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
(in millions, except per share and share amounts)			
Numerator:			
Net income	\$ 1,052	\$ 1,019	\$ 917
Less: Preferred stock dividend requirement	—	—	50
Income available to common shareholders - basic and diluted	<u>\$ 1,052</u>	<u>\$ 1,019</u>	<u>\$ 867</u>
Denominator:			
Weighted average common shares outstanding - basic	652,671,000	643,163,000	630,947,000
Plus:			
Restricted stock	1,938,000	974,000	2,232,000
Equity forwards	1,000,000	—	—
Convertible notes (1)	41,000	—	—
Weighted average common shares outstanding - diluted	<u>655,650,000</u>	<u>644,137,000</u>	<u>633,179,000</u>
Earnings per Common Share:			
Basic	<u>\$ 1.61</u>	<u>\$ 1.58</u>	<u>\$ 1.37</u>
Diluted	<u>\$ 1.60</u>	<u>\$ 1.58</u>	<u>\$ 1.37</u>

(1) Related to the 2026 Convertible Notes.

(16) Reportable Segments

The Registrants' determination of reportable segments considers the strategic operating units under which its CODM manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments.

As of December 31, 2025, reportable segments by Registrant and information about each Registrant's CODM were as follows:

CenterPoint Energy

- CenterPoint Energy's Electric reportable segment consisted of (i) electric transmission and distribution services in the Texas Gulf Coast area in the ERCOT region; (ii) electric transmission and distribution services primarily to southwestern Indiana, and (iii) power generation and wholesale power operations in the MISO region.
- CenterPoint Energy's Natural Gas reportable segment following the closing of the sale of the Louisiana and Mississippi natural gas LDC businesses on March 31, 2025 consisted of (i) intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial and industrial customers in Indiana, Minnesota, Ohio and Texas; and (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline

companies through CEIP. On October 20, 2025, CenterPoint Energy, through CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

- CenterPoint Energy's Corporate and Other reportable segment consisted of energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group, and corporate support operations that support all of CenterPoint Energy's business operations. CenterPoint Energy's Corporate and Other also includes office buildings and other real estate used for business operations.

CenterPoint Energy's CODM, the President and Chief Executive Officer, evaluates performance for all of its reportable segments based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

Houston Electric

- Houston Electric's single reportable segment consisted of electric transmission services to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston.

Houston Electric's CODM, the President and Chief Executive Officer, evaluates performance for its single reportable segment based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

CERC

- CERC's single reportable segment following the closing of the sale of the Louisiana and Mississippi natural gas LDC businesses on March 31, 2025 consisted of (i) intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, and industrial customers in Indiana, Minnesota, Ohio and Texas; and (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP. On October 20, 2025, CenterPoint Energy, through CERC Corp., entered into the Ohio Securities Purchase Agreement to sell all of the issued and outstanding equity interests in CEOH. The transaction is expected to close in the fourth quarter of 2026, subject to the satisfaction of customary closing conditions. For further information, see Note 4 to the consolidated financial statements.

CERC's CODM, the President and Chief Executive Officer, evaluates performance for its single reportable segment based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

Expenditures for long-lived assets include property, plant and equipment. Intersegment sales are eliminated in consolidation, except as described in Note 1.

Financial data for reportable segments is as follows for the periods presented:

CenterPoint Energy

Year Ended December 31, 2025						
	Electric	Natural Gas	Corporate and Other	Total Reportable Segments	Eliminations	Total
	(in millions)					
Revenues from external customers	\$ 4,866	\$ 4,483	\$ 8	\$ 9,357	\$ —	\$ 9,357
Intersegment revenues	—	3	—	3	(3)	—
Utility natural gas, fuel and purchased power	270	1,846	—	2,116	(3)	2,113
Non-utility cost of revenues, including natural gas	—	4	—	4	—	4
Operation and maintenance expenses	2,084	931	9	3,024	—	3,024
Depreciation and amortization	946	563	21	1,530	—	1,530
Taxes other than income taxes	321	245	10	576	—	576
Interest expense and other finance charges	445	208	282	935	(32)	903
Interest income (1)	(15)	(11)	(17)	(43)	32	(11)
Other expense (income), net (2)	(62)	33	—	(29)	—	(29)
Income tax expense (benefit)	172	97	(74)	195	—	195
Net income (loss)	\$ 705	\$ 570	\$ (223)	\$ 1,052	\$ —	\$ 1,052
Year Ended December 31, 2024						
	Electric	Natural Gas	Corporate and Other	Total Reportable Segments	Eliminations	Total
	(in millions)					
Revenues from external customers	\$ 4,590	\$ 4,048	\$ 5	\$ 8,643	\$ —	\$ 8,643
Intersegment revenues	—	2	—	2	(2)	—
Utility natural gas, fuel and purchased power	198	1,520	(1)	1,717	(2)	1,715
Non-utility cost of revenues, including natural gas	—	3	—	3	—	3
Operation and maintenance expenses	2,072	881	(4)	2,949	—	2,949
Depreciation and amortization	877	542	20	1,439	—	1,439
Taxes other than income taxes	304	237	6	547	—	547
Interest expense and other finance charges	372	207	286	865	(27)	838
Interest income (1)	(18)	(2)	(14)	(34)	27	(7)
Other income, net (2)	(43)	(12)	—	(55)	—	(55)
Income tax expense (benefit)	157	108	(70)	195	—	195
Net income (loss)	\$ 671	\$ 566	\$ (218)	\$ 1,019	\$ —	\$ 1,019

Year Ended December 31, 2023

	Electric	Natural Gas	Corporate and Other	Total Reportable Segments		Eliminations	Total
				(in millions)			
Revenues from external customers	\$ 4,290	\$ 4,276	\$ 130	\$ 8,696	\$ —	\$ 8,696	
Intersegment revenues	—	3	—	3	(3)	—	
Utility natural gas, fuel and purchased power	176	1,888	—	2,064	(3)	2,061	
Non-utility cost of revenues, including natural gas	—	3	96	99	—	99	
Operation and maintenance expenses	1,880	949	21	2,850	—	2,850	
Depreciation and amortization	872	513	16	1,401	—	1,401	
Taxes other than income taxes	272	245	8	525	—	525	
Interest expense and other finance charges	303	188	264	755	(54)	701	
Interest income (1)	(19)	(10)	(34)	(63)	54	(9)	
Other expense (income), net (2)	(37)	(5)	23	(19)	—	(19)	
Income tax expense (benefit)	\$ 189	\$ (25)	\$ 6	\$ 170	\$ —	\$ 170	
Net income (loss)	\$ 654	\$ 533	\$ (270)	\$ 917	\$ —	\$ 917	

(1) Interest income from Securitization Bonds of \$1 million, \$3 million, and \$4 million for the years ended December 31, 2025, 2024 and 2023, respectively, is included in Other income (expense), net on CenterPoint Energy's Statements of Consolidated Income.

(2) Other income (expense), net primarily includes AFUDC equity, non-service cost for pension and postretirement benefits, Gain (loss) on equity securities, Gain (loss) on indexed debt securities and Gain (loss) on sale.

	Total Assets		Expenditures for Long-lived Assets		
	As of December 31,		Year Ended December 31,		
	2025	2024	2025	2024	2023
	(in millions)				
Electric	\$ 26,649	\$ 23,936	\$ 3,683	\$ 3,099	\$ 2,660
Natural Gas	18,405	18,583	1,657	1,524	1,697
Corporate and Other, net of eliminations (1)	1,480	1,249	65	26	13
Consolidated	\$ 46,534	\$ 43,768	\$ 5,405	\$ 4,649	\$ 4,370

(1) Total assets included pension and other postemployment-related regulatory assets of \$383 million and \$384 million as of December 31, 2025 and 2024, respectively.

Houston Electric

Houston Electric consists of a single reportable segment. For financial data related to income and expenses for the single reportable segment, see Houston Electric's Statements of Consolidated Income. For financial data related to segment total assets, see Houston Electric's Consolidated Balance Sheets. Financial data related to interest income and expenditures for long-lived assets is as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Interest income (1)	\$ 13	\$ 16	\$ 14
Expenditures for long-lived assets	2,918	2,738	2,309

(1) Reflected in Other income (expense), net on Houston Electric's Statements of Consolidated Income.

CERC

CERC consists of a single reportable segment. For financial data related to income and expenses for the single reportable segment, see CERC's Statements of Consolidated Income. For financial data related to segment total assets, see CERC's Consolidated Balance Sheets. Financial data related to interest income and expenditures for long-lived assets is as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Interest income (1)	\$ 10	\$ 2	\$ 10
Expenditures for long-lived assets	1,581	1,485	1,568

(1) Reflected in Other income (expense), net on CERC's Statements of Consolidated Income.

Major Customers (Houston Electric)

Houston Electric's revenues from major external customers are as follows for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
	(in millions)		
Affiliates of NRG	\$ 1,229	\$ 1,169	\$ 1,106
Affiliates of Vistra Energy Corp.	693	605	539

Revenues by Products and Services

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Electric delivery	\$ 4,109	\$ 4,084	\$ —	\$ 3,963	\$ 3,939	\$ —	\$ 3,701	\$ 3,677	\$ —
Retail electric sales	736	—	—	622	—	—	569	—	—
Wholesale electric sales	19	—	—	4	—	—	20	—	—
Retail gas sales	4,266	—	4,126	3,837	—	3,716	4,078	—	3,951
Gas transportation	11	—	11	11	—	11	11	—	11
Energy products and services	216	—	207	206	—	198	317	—	187
Total	\$ 9,357	\$ 4,084	\$ 4,344	\$ 8,643	\$ 3,939	\$ 3,925	\$ 8,696	\$ 3,677	\$ 4,149

(17) Supplemental Disclosure of Cash Flow and Balance Sheet Information

Supplemental Disclosure of Cash Flow Information

The tables below provide supplemental disclosure of cash flow information for the periods presented:

	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Cash Payments (Refunds):									
Interest, net of capitalized interest	\$ 983	\$ 392	\$ 233	\$ 805	\$ 321	\$ 190	\$ 664	\$ 287	\$ 175
Income taxes									
Federal income taxes	\$ (1)	\$ —	\$ —	\$ (5)	\$ —	\$ —	\$ 196	\$ 12	\$ 113
State income taxes									
Indiana	(11)	—	—	—	—	—	—	—	—
Louisiana	(10)	—	—	(10)	—	1	—	—	—
New Mexico	—	—	—	(2)	—	—	—	—	—
Texas	8	18	2	10	26	2	15	—	—
Minnesota	(4)	—	(5)	—	—	—	—	—	—
Other states	(3)	—	(1)	(2)	—	—	4	—	2
Total income tax payments (refunds), net (1)	\$ (21)	\$ 18	\$ (4)	\$ (9)	\$ 26	\$ 3	\$ 215	\$ 12	\$ 115
Non-cash transactions:									
Accounts payable related to capital expenditures	\$ 492	\$ 367	\$ 126	\$ 467	\$ 381	\$ 103	\$ 246	\$ 166	\$ 74
ROU assets obtained in exchange for lease liabilities (2)	\$ 36	\$ 2	\$ (1)	\$ 18	\$ —	\$ 13	\$ 3	\$ 1	\$ —

- (1) CenterPoint Energy's \$215 million income tax payments in 2023 were attributable to recovery of extraordinary gas costs incurred in the February 2021 Winter Storm through the Railroad Commission ordered securitization.
- (2) Excludes ROU assets obtained through prepayment of the lease liabilities; see Note 19 for additional detail on ROU assets as of the periods presented. Amounts presented for CenterPoint Energy and CERC include ROU assets and lease liabilities derecognized as part of the sale of the Louisiana and Mississippi natural gas LDC businesses on March 31, 2025; see Note 4 for additional detail on the transaction.

The table below provides a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets to the amount reported in the Statements of Consolidated Cash Flows for the periods presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Cash and cash equivalents (1)	\$ 38	\$ 25	\$ —	\$ 24	\$ 14	\$ 2
Restricted cash included in Prepaid expenses and other current assets (2)	11	4	—	6	—	—
Total cash, cash equivalents and restricted cash shown in Statements of Consolidated Cash Flows	\$ 49	\$ 29	\$ —	\$ 30	\$ 14	\$ 2

- (1) Cash and cash equivalents related to VIEs as of December 31, 2025 and 2024 included \$34 million and \$21 million, respectively, at CenterPoint Energy and \$25 million and \$14 million, respectively, at Houston Electric.
- (2) Restricted cash primarily related to accounts established by CenterPoint Energy and Houston Electric in connection with the issuance of the Securitization Bonds to collateralize the Securitization Bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the Securitization Bonds.

Supplemental Disclosure of Balance Sheet Information

Included in other current liabilities on Houston Electric's Consolidated Balance Sheets as of December 31, 2025 and 2024 was \$119 million and \$85 million, respectively, of builder deposits. Included in other current liabilities on CERC's Consolidated Balance Sheets as of December 31, 2025 and 2024 was \$80 million and \$98 million, respectively, of credits related to customers on budget billing programs.

(18) Related Party Transactions (Houston Electric and CERC)

Houston Electric and CERC participate in CenterPoint Energy's money pool through which they can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the CenterPoint Energy money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper.

The table below summarizes CenterPoint Energy money pool activity as of the dates presented:

	December 31, 2025		December 31, 2024	
	Houston Electric	CERC	Houston Electric	CERC
	(in millions, except interest rates)			
Money pool investments (borrowings) (1)	\$ (54)	\$ (291)	\$ 368	\$ —
Weighted average interest rate	3.83 %	3.83 %	4.65 %	— %

(1) Included in Accounts and notes payable—affiliated companies in Houston Electric's and CERC's respective Consolidated Balance Sheets as of December 31, 2025 and Accounts and notes receivable—affiliated companies in Houston Electric's Consolidated Balance Sheets as of December 31, 2024, as applicable.

Houston Electric and CERC affiliate-related transactions were as follows for the periods presented:

	Year Ended December 31,					
	2025		2024		2023	
	Houston Electric	CERC	Houston Electric	CERC	Houston Electric	CERC
	(in millions)					
Interest income, net (1)	\$ 1	\$ 7	\$ 9	\$ 2	\$ 2	\$ 10

(1) Interest income is included in Other, net on Houston Electric's and CERC's respective Statements of Consolidated Income.

CenterPoint Energy provides some corporate services to Houston Electric and CERC. The costs of services have been charged directly to Houston Electric and CERC using methods that management believes are reasonable. These methods include usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. Houston Electric provides certain services to CERC. These services are billed at actual cost, either directly or as an allocation and include fleet services, shop services, geographic services, surveying and right-of-way services, radio communications, data circuit management and field operations. Additionally, CERC provides certain services to Houston Electric. These services are billed at actual cost, either directly or as an allocation and include line locating and other miscellaneous services. These charges are not necessarily indicative of what would have been incurred had Houston Electric and CERC not been affiliates.

The table below presents amounts charged for these services, which are included primarily in Operation and maintenance expenses on Houston Electric's and CERC's respective Statements of Consolidated Income, for the periods presented:

	Year Ended December 31,					
	2025		2024		2023	
	Houston Electric	CERC	Houston Electric	CERC	Houston Electric	CERC
	(in millions)					
Corporate service charges	\$ 201	\$ 228	\$ 173	\$ 213	\$ 173	\$ 236
Affiliate service charges (billings), net	(4)	4	(5)	5	(10)	10

(19) Leases

In 2021, Houston Electric entered into a temporary short-term lease and long-term leases for TEEEF. The short-term lease agreement expired on December 31, 2022. Effective January 1, 2023, all TEEEF assets were leased under the long-term lease agreement. Expenses associated with the short-term lease, including carrying costs, are deferred to a regulatory asset and totaled \$78 million and \$89 million as of December 31, 2025 and 2024, respectively.

The long-term lease agreement includes up to 519 MW of TEEEF, all of which was delivered as of December 31, 2022, triggering lease commencement at delivery, with an initial term ending in 2029 for all TEEEF leases. The remaining finance lease liability associated with the commenced long-term TEEEF agreement was not significant as of December 31, 2025 and 2024 and relates to removal costs that will be incurred at the end of the lease term. As of December 31, 2025, Houston Electric had secured a first lien on all the assets leased under the prepayment agreement. For TEEEF units included within the rate-regulated utilities, expenses associated with the long-term lease, including variable costs associated with the operation and maintenance of the TEEEF assets, depreciation expense on the right of use asset and carrying costs, are deferred to a regulatory asset as a recoverable cost under the 2021 Texas legislation and totaled \$123 million and \$158 million as of December 31, 2025 and 2024, respectively. For further discussion of the regulatory impacts, see Note 7.

The components of lease cost, included in Operation and maintenance expense on the Registrants' respective Statements of Consolidated Income, are as follows for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Operating lease cost	\$ 8	\$ 3	\$ 2	\$ 6	\$ 3	\$ 2	\$ 6	\$ 3	\$ 2
Short-term lease cost	26	25	—	12	11	—	31	30	—
Total lease cost (1)	\$ 34	\$ 28	\$ 2	\$ 18	\$ 14	\$ 2	\$ 37	\$ 33	\$ 2

(1) For TEEEF units included within the rate-regulated utilities, CenterPoint Energy and Houston Electric defer finance lease costs for TEEEF to Regulatory assets for recovery rather than to Depreciation and amortization in the Statements of Consolidated Income. For the year ended December 31, 2025, CenterPoint Energy and Houston Electric recognized \$59 million of finance lease cost within Depreciation and amortization in the Statements of Consolidated Income, which represents the period of time certain TEEEF units were not eligible for regulatory deferral.

The components of lease income were as follows for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Operating lease income	\$ 9	\$ —	\$ 6	\$ 7	\$ —	\$ 5	\$ 6	\$ 1	\$ 4
Variable lease income	1	—	—	1	—	—	2	—	—
Total lease income	\$ 10	\$ —	\$ 6	\$ 8	\$ —	\$ 5	\$ 8	\$ 1	\$ 4

Supplemental balance sheet information related to leases was as follows as of the dates presented:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Assets:						
Operating ROU assets (1)	\$ 61	\$ 5	\$ 14	\$ 27	\$ 5	\$ 15
Finance ROU assets (2)	335	335	—	430	430	—
Total leased assets	<u>\$ 396</u>	<u>\$ 340</u>	<u>\$ 14</u>	<u>\$ 457</u>	<u>\$ 435</u>	<u>\$ 15</u>
Liabilities:						
Current operating lease liability (3)	\$ 5	\$ 2	\$ —	\$ 3	\$ 1	\$ 1
Non-current operating lease liability (4)	57	2	14	25	3	14
Total leased liabilities (5)	<u>\$ 62</u>	<u>\$ 4</u>	<u>\$ 14</u>	<u>\$ 28</u>	<u>\$ 4</u>	<u>\$ 15</u>

- (1) Included in Other assets in the Registrants' respective Consolidated Balance Sheets, net of accumulated amortization.
- (2) Included in Property, Plant and Equipment in the Registrants' respective Consolidated Balance Sheets, net of accumulated amortization.
- (3) Included in Other current liabilities in the Registrants' respective Consolidated Balance Sheets.
- (4) Included in Other non-current liabilities in the Registrants' respective Consolidated Balance Sheets.
- (5) Finance lease liabilities were not material as of December 31, 2025 or 2024.

As of the dates presented, the weighted-average remaining lease term and weighted-average discount rate for the Registrants' finance and operating leases were as follows:

	December 31, 2025			December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Weighted-average remaining lease term (in years) - operating leases	27.2	7.3	20.9	17.7	2.9	20.6
Weighted-average discount rate - operating leases	5.47 %	4.65 %	5.09 %	4.92 %	4.11 %	5.03 %
Weighted-average remaining lease term (in years) - finance leases	3.5	3.5	—	4.5	4.5	—
Weighted-average discount rate - finance leases	3.60 %	3.60 %	—	3.60 %	3.60 %	—

As of December 31, 2025, finance lease liabilities were not significant to the Registrants. As of December 31, 2025, maturities of operating lease liabilities were as follows:

	CenterPoint Energy	Houston Electric	CERC
	(in millions)		
2026	\$ 6	\$ 2	\$ 1
2027	5	1	1
2028	4	—	1
2029	4	—	1
2030	3	—	1
Thereafter	108	2	19
Total lease payments	<u>130</u>	<u>5</u>	<u>24</u>
Less: Interest	68	1	10
Present value of lease liabilities	<u>\$ 62</u>	<u>\$ 4</u>	<u>\$ 14</u>

As of December 31, 2025, future minimum finance lease payments to be received were not significant to the Registrants. As of December 31, 2025, maturities of undiscounted operating lease payments to be received were as follows:

	CenterPoint Energy	Houston Electric	CERC
	(in millions)		
2026	\$ 9	\$ —	\$ 6
2027	9	—	7
2028	4	—	2
2029	1	—	—
2030	1	—	—
Thereafter	3	—	—
Total lease payments to be received	<u>\$ 27</u>	<u>\$ —</u>	<u>\$ 15</u>

Other information related to leases is as follows for the periods presented:

	Year Ended December 31,								
	2025			2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Operating cash flows from operating leases included in the measurement of lease liabilities	\$ 6	\$ 2	\$ 1	\$ 5	\$ 2	\$ 2	\$ 5	\$ 2	\$ 2

See Note 17 for information on ROU assets obtained in exchange for operating lease liabilities.

(20) Subsequent Events

CERC Term Loan

In January 2026, CERC Corp. entered into a delayed draw term loan agreement pursuant to which the banks party thereto have committed to provide term loans in an aggregate principal amount of up to \$800 million by March 30, 2026 in up to three separate borrowings, subject to the satisfaction or waiver of certain customary conditions. If not fully utilized, the term loan commitments expire on March 31, 2026. The maturity date of the term loan is July 16, 2027. The borrowings under the term loan agreement bear interest at CERC's option, at a rate per annum equal to either (i) Term SOFR (as defined in the term loan agreement), plus a margin of 0.85%, or (ii) the Alternate Base Rate (as defined in the term loan agreement). CERC Corp. borrowed \$500 million on January 20, 2026, and expects to borrow the remaining \$300 million during the first quarter of 2026. CERC intends to use the proceeds thereof for general corporate purposes.

CERC Prepayment Notice

On February 11, 2026, CERC Corp. commenced sending out notices of full prepayment relating to (i) \$10 million aggregate principal amount of its 4.25% Senior Notes, Series B, due June 5, 2043, (ii) \$40 million aggregate principal amount of its 4.36% Senior Notes, Series B, due December 15, 2045, (iii) \$35 million aggregate principal amount of its 5.99% Senior Notes, Series C, due November 30, 2041, (iv) \$60 million aggregate principal amount of its 5.02% Senior Notes, Series B, due November 30, 2026 and (v) \$100 million aggregate principal amount of its 5.00% Senior Notes due February 3, 2042, pursuant to Note Purchase Agreements, each dated as of May 27, 2022, by and among CERC Corp. and the purchasers party thereto. Such notes are expected to be prepaid on March 27, 2026 at 100% of the principal amount plus accrued and unpaid interest and a Make-Whole Amount (as defined in the respective Note Purchase Agreements).

Series 2026-A Senior Secured System Restoration Bonds (Houston Electric)

On February 18, 2026, Houston Electric and Restoration Bond Company III entered into an underwriting agreement with respect to the purchase and sale of up to approximately \$1.193 billion aggregate principal amount of Restoration Bond Company III's Series 2026-A Senior Secured System Restoration Bonds. Subject to the satisfaction of customary closing conditions, Restoration Bond Company III expects to issue the Series 2026-A Senior Secured System Restoration Bonds on February 26, 2026 in three tranches with initial principal amounts of \$298,370,000, \$397,825,000 and \$497,279,000, interest

rates of 3.899%, 4.480% and 4.864% and final maturity dates of December 2031, June 2036 and December 2040, respectively. Restoration Bond Company III intends to use the net proceeds from the issuance of the Series 2026-A Senior Secured System Restoration Bonds to purchase the system restoration property from Houston Electric.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Disclosure Controls And Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, the Registrants carried out separate evaluations, under the supervision and with the participation of each company's management, including the principal executive officer and principal financial officer, of the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report. Based on those evaluations, the principal executive officer and principal financial officer, in each case, concluded that the disclosure controls and procedures were effective as of December 31, 2025 to provide assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in the Registrants' internal controls over financial reporting that occurred during the three months ended December 31, 2025 that has materially affected, or is reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The Registrants' management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the Registrants' principal executive and principal financial officers and effected by the Board, as well as the Registrants' management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Registrants;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Registrants are being made only in accordance with authorizations of management and directors of the Registrants; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Registrants' assets that could have a material effect on the financial statements.

Management has designed its internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Management's assessment included review and testing of both the design effectiveness and operating effectiveness of controls over all relevant assertions related to all significant accounts and disclosures in the financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of the Registrants' management, including their respective principal executive officers and principal financial officers, the Registrants conducted an evaluation of the effectiveness of their internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Registrants' evaluation under the framework in *Internal Control — Integrated Framework* (2013), the Registrants' management has concluded, in each case, that their internal control over financial reporting was effective as of December 31, 2025.

Deloitte & Touche LLP, CenterPoint Energy's independent registered public accounting firm, has issued an attestation report on the effectiveness of CenterPoint Energy's internal control over financial reporting as of December 31, 2025 which is set forth below. This report is not applicable to Houston Electric or CERC as they are not accelerated or large accelerated filers.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of CenterPoint Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Company and our report dated February 19, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 19, 2026

Item 9B. Other Information

None.

Rule 10b5-1 Trading Arrangements

During the three months ended December 31, 2025, no director or officer of CenterPoint Energy, Houston Electric or CERC adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408 of Regulation S-K.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

For CenterPoint Energy, the information called for by Item 10, to the extent not set forth in “Information About Our Executive Officers” in Item 1 of Part I of this report, will be set forth in the definitive proxy statement relating to CenterPoint Energy’s 2026 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 10 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 11. Executive Compensation

For CenterPoint Energy, the information called for by Item 11 will be set forth in the definitive proxy statement relating to CenterPoint Energy’s 2026 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 11 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

For CenterPoint Energy, the information called for by Item 12 will be set forth in the definitive proxy statement relating to CenterPoint Energy’s 2026 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 12 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 13. Certain Relationships and Related Transactions, and Director Independence

For CenterPoint Energy, the information called for by Item 13 will be set forth in the definitive proxy statement relating to CenterPoint Energy’s 2026 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 13 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 14. Principal Accounting Fees and Services

For CenterPoint Energy, the information called for by Item 14 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2026 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Aggregate fees billed to Houston Electric and CERC during the periods presented by their principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,			
	2025		2024	
	Houston Electric	CERC	Houston Electric	CERC
Audit fees (1)	\$ 2,443,540	\$ 3,829,800	\$ 948,480	\$ 1,337,600
Audit-related fees (2)	1,412,641	284,500	1,088,145	449,000
Total audit and audit-related fees	3,856,181	4,114,300	2,036,625	1,786,600
Tax fees	—	—	—	—
All other fees	—	—	—	—
Total fees	<u>\$ 3,856,181</u>	<u>\$ 4,114,300</u>	<u>\$ 2,036,625</u>	<u>\$ 1,786,600</u>

- (1) For 2025 and 2024, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.
- (2) For 2025 and 2024, amounts include fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

Each of Houston Electric and CERC is not required to have, and does not have, an audit committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements.

CenterPoint Energy	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	92
Statements of Consolidated Income for the Three Years Ended December 31, 2025	94
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2025	95
Consolidated Balance Sheets as of December 31, 2025 and 2024	96
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2025	98
Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2025	99
Houston Electric	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	100
Statements of Consolidated Income for the Three Years Ended December 31, 2025	102
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2025	103
Consolidated Balance Sheets as of December 31, 2025 and 2024	104
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2025	105
Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2025	106
CERC	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	107
Statements of Consolidated Income for the Three Years Ended December 31, 2025	109
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2025	110
Consolidated Balance Sheets as of December 31, 2025 and 2024	111
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Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2025	114
Combined Notes to Consolidated Financial Statements	115

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2025

The following schedules are omitted by the Registrants because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, II, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 186, which index also includes the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

Item 16. Form 10-K Summary

None.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE COMBINED ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2025

INDEX OF EXHIBITS

Exhibits included with this report are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K. The Registrants have not filed the exhibits and schedules to Exhibit 2. The Registrants hereby agree to furnish supplementally a copy of any schedule omitted from Exhibit 2 to the SEC upon request.

The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
2(a)	— Asset Purchase Agreement by and between CenterPoint Energy Resources Corp. and Southern Col Midco, LLC, dated as of April 29, 2021	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2021	1-31447	2.4	X		X
2(b)	— Asset Purchase Agreement, dated February 19, 2024, among CenterPoint Energy Resources Corp. and Delta Utilities No. LA, LLC, Delta Utilities S. LA, LLC, Delta Utilities MS, LLC, and Delta Shared Services Co., LLC	CenterPoint Energy's Form 8-K dated February 19, 2024	1-31447	1.1	X		X
2(c)	— Securities Purchase Agreement, dated October 20, 2025, by and between CenterPoint Energy Resources Corp. and National Fuel Gas Company	CenterPoint Energy's Form 8-K dated October 20, 2025	1-31447	2.1	X		X
3(a)	— Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy's Form 8-K dated July 24, 2008	1-31447	3.2	X		
3(b)	— Restated Certificate of Formation of Houston Electric	Houston Electric's Form 10-Q for the quarter ended June 30, 2011	1-3187	3.1		X	
3(c)	— Certificate of Incorporation of RERC Corp.	CERC Form 10-K for the year ended December 31, 1997	1-13265	3(a)(1)			X
3(d)	— Certificate of Amendment changing the name to Reliant Energy Resources Corp.	CERC Form 10-K for the year ended December 31, 1998	1-13265	3(a)(3)			X
3(e)	— Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	CERC Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)			X

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
3(f)	— Fifth Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy's Form 8-K dated September 26, 2025	1-31447	3.1	X		
3(g)	— Amended and Restated Limited Liability Company Agreement of Houston Electric	Houston Electric's Form 10-Q for the quarter ended June 30, 2011	1-3187	3.2		X	
3(h)	— Bylaws of RERC Corp.	CERC Form 10-K for the year ended December 31, 1997	1-13265	3(b)			X
3(i)	— Statement of Resolutions Deleting Shares Designated Series A Preferred Stock of CenterPoint Energy	CenterPoint Energy's Form 10-K for the year ended December 31, 2011	1-31447	3(c)	X		
4(a)	— Form of CenterPoint Energy Stock Certificate	CenterPoint Energy's Registration Statement on Form S-4	333-69502	4.1	X		
4(b)(1)	— Mortgage and Deed of Trust, dated November 1, 1944 between Houston Lighting and Power Company (HL&P) and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented by 20 Supplemental Indentures thereto	HL&P's Form S-7 filed on August 25, 1977	2-59748	2(b)	X	X	
4(b)(2)	— Twenty-First through Fiftieth Supplemental Indentures to Exhibit 4(b)(1)	HL&P's Form 10-K for the year ended December 31, 1989	1-3187	4(a)(2)	X	X	
4(b)(3)	— Fifty-First Supplemental Indenture to Exhibit 4(b)(1) dated as of March 25, 1991	HL&P's Form 10-Q for the quarter ended June 30, 1991	1-3187	4(a)	X	X	
4(b)(4)	— Fifty-Second through Fifty-Fifth Supplemental Indentures to Exhibit 4(b)(1) each dated as of March 1, 1992	HL&P's Form 10-Q for the quarter ended March 31, 1992	1-3187	4	X	X	
4(b)(5)	— Fifty-Sixth and Fifty-Seventh Supplemental Indentures to Exhibit 4(b)(1) each dated as of October 1, 1992	HL&P's Form 10-Q for the quarter ended September 30, 1992	1-3187	4	X	X	
4(b)(6)	— Fifty-Eighth and Fifty-Ninth Supplemental Indentures to Exhibit 4(b)(1) each dated as of March 1, 1993	HL&P's Form 10-Q for the quarter ended March 31, 1993	1-3187	4	X	X	
4(b)(7)	— Sixtieth Supplemental Indenture to Exhibit 4(b)(1) dated as of July 1, 1993	HL&P's Form 10-Q for the quarter ended June 30, 1993	1-3187	4	X	X	

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(b)(8)	— Sixty-First through Sixty-Third Supplemental Indentures to Exhibit 4(b)(1) each dated as of December 1, 1993	HL&P's Form 10-K for the year ended December 31, 1993	1-3187	4(a)(8)	X	X	
4(b)(9)	— Sixty-Fourth and Sixty-Fifth Supplemental Indentures to Exhibit 4(b)(1) each dated as of July 1, 1995	HL&P's Form 10-K for the year ended December 31, 1995	1-3187	4(a)(9)	X	X	
4(c)(1)	— General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee	Houston Electric's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(1)	X	X	
4(c)(2)	— Third Supplemental Indenture to Exhibit 4(c)(1), dated as of October 10, 2002	Houston Electric's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(4)	X	X	
4(c)(3)	— Officer's Certificates dated October 10, 2002 setting forth the form, terms and provisions of the First through Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(10)	X	X	
4(c)(4)	— Ninth Supplemental Indenture to Exhibit 4(c)(1), dated as of November 12, 2002	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	4(e)(10)	X	X	
4(c)(5)	— Tenth Supplemental Indenture to Exhibit 4(c)(1), dated as of March 18, 2003	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.1	X	X	
4(c)(6)	— Officer's Certificate dated March 18, 2003 setting forth the form, terms and provisions of the Tenth Series and Eleventh Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.2	X	X	
4(c)(7)	— Twentieth Supplemental Indenture to Exhibit 4(c)(1), dated as of December 9, 2008	Houston Electric's Form 8-K dated January 6, 2009	1-3187	4.2	X	X	
4(c)(8)	— Twenty-Second Supplemental Indenture to Exhibit 4(c)(1) dated as of August 10, 2012	CenterPoint Energy's Form 10-K for the year ended December 31, 2012	1-31447	4(e)(33)	X	X	
4(c)(9)	— Officer's Certificate, dated August 10, 2012 setting forth the form, terms and provisions of the Twenty-Second Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2012	1-31447	4(e)(34)	X	X	
4(c)(10)	— Twenty-Third Supplemental Indenture to Exhibit 4(c)(1) dated as of March 17, 2014	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2014	1-31447	4.10	X	X	

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(c)(11)	— Officer's Certificate, dated as of March 17, 2014, setting forth the form, terms and provisions of the Twenty-Third Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2014	1-31447	4.11	X	X	
4(c)(12)	— Twenty-Fifth Supplemental Indenture to Exhibit 4(c)(1), dated as of August 11, 2016	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2016	1-31447	4.5	X	X	
4(c)(13)	— Officer's Certificate, dated as of August 11, 2016, setting forth the form, terms and provisions of the Twenty-Sixth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2016	1-31447	4.6	X	X	
4(c)(14)	— Twenty-Sixth Supplemental Indenture to Exhibit 4(c)(1), dated as of January 12, 2017	CenterPoint Energy's Form 10-K for the year ended December 31, 2016	1-31447	4(c)(41)	X	X	
4(c)(15)	— Officer's Certificate, dated as of January 12, 2017, setting forth the form, terms and provisions of the Twenty-Seventh Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2016	1-31447	4(c)(42)	X	X	
4(c)(16)	— Twenty-Seventh Supplemental Indenture to Exhibit 4(c)(1) dated as of February 28, 2018	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2018	1-31447	4.9	X	X	
4(c)(17)	— Officer's Certificate, dated as of February 28, 2018, setting forth the form, terms and provisions of the Twenty-Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2018	1-31447	4.10	X	X	
4(c)(18)	— Twenty-Eighth Supplemental Indenture to Exhibit 4(c)(1) dated as of January 15, 2019	Houston Electric's Form 8-K dated January 10, 2019	1-3187	4.4	X	X	
4(c)(19)	— Officer's Certificate, dated as of January 15, 2019, setting forth the form, terms and provisions of the Twenty-Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2018	1-31447	4(h)(24)	X	X	
4(c)(20)	— Twenty-Ninth Supplemental Indenture to Exhibit 4(c)(1) dated as of June 5, 2020	Houston Electric's Form 8-K dated June 2, 2020	1-3187	4.4	X	X	
4(c)(21)	— Officer's Certificate, dated as of June 5, 2020, setting forth the form, terms and provisions of the Thirtieth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2020	1-31447	4.26	X	X	
4(c)(22)	— Thirtieth Supplemental Indenture to Exhibit 4(c)(1), dated as of March 11, 2021	Houston Electric's Form 8-K dated March 8, 2021	1-3187	4.4	X	X	

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(c)(23)	— Officer's Certificate, dated as of March 11, 2021, setting forth the form, terms and provisions of the Thirty-First and Thirty-Second Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2021	1-31447	4.22	X	X	
4(c)(24)	— Thirty-First Supplemental Indenture to Exhibit 4(c)(1), dated as of February 28, 2022	Houston Electric's Form 8-K dated February 23, 2022	1-3187	4.4		X	
4(c)(25)	— Officer's Certificate, dated as of February 28, 2022, setting forth the form, terms and provisions of the Thirty-Third and Thirty-Fourth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2022	1-31447	4.11		X	
4(c)(26)	— Thirty-Second Supplemental Indenture to Exhibit 4(c)(1), dated as of September 15, 2022	Houston Electric's Form 8-K dated September 12, 2022	1-3187	4.4		X	
4(c)(27)	— Officer's Certificate, dated September 15, 2022, setting forth the form, terms and provisions of the Thirty-Fifth and Thirty-Sixth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2022	1-31447	4.7		X	
4(c)(28)	— Thirty-Third Supplemental Indenture to Exhibit 4(c)(1), dated as of March 23, 2023	Houston Electric's Form 8-K dated March 20, 2023	1-3187	4.4		X	
4(c)(29)	— Officer's Certificate, dated March 23, 2023, setting forth the form, terms and provisions of the Thirty-Seventh and Thirty-Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2023	1-31447	4.11		X	
4(c)(30)	— Thirty-Fourth Supplemental Indenture to Exhibit 4(c)(1), dated as of September 18, 2023	Houston Electric's Form 8-K dated September 13, 2023	1-3187	4.4		X	
4(c)(31)	— Officer's Certificate, dated September 18, 2023, setting forth the form, terms and provisions of the Thirty-Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	4.9		X	
4(c)(32)	— Thirty-Fifth Supplemental Indenture to Exhibit 4(c)(1), dated as of February 29, 2024	Houston Electric's Form 8-K dated February 26, 2024	1-3187	4.4		X	
4(c)(33)	— Officer's Certificate, dated as of February 29, 2024, setting forth the form, terms and provisions of the Fortieth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	4.6		X	
4(c)(34)	— Thirty-Sixth Supplemental Indenture to Exhibit 4(c)(1), dated as of November 4, 2024	Houston Electric's Form 8-K dated October 31, 2024	1-3187	4.4		X	

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(c)(35)	— Officer's Certificate, dated as of November 4, 2024, setting forth the form, terms and provisions of the Forty-First Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2024	1-3187	4(c)(35)		X	
4(c)(36)	— Thirty-Seventh Supplemental Indenture to Exhibit 4(c)(1), dated as of February 27, 2025	Houston Electric's Form 8-K dated February 26, 2025	1-3187	4.4		X	
4(c)(37)	— Officer's Certificate, dated as of February 27, 2025	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2025	1-3187	4.5		X	
4(c)(38)	— Thirty-Eighth Supplemental Indenture to Exhibit 4(c)(1), dated as of August 7, 2025	Houston Electric's Form 8-K dated August 5, 2025	1-3187	4.4		X	
4(c)(39)	— Officer's Certificate, dated as of August 7, 2025	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2025	1-3187	4.11		X	
4(d)(1)	— Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. (RERC Corp.) and Chase Bank of Texas, National Association, as Trustee	CERC Corp.'s Form 8-K dated February 5, 1998	1-13265	4.1	X		X
4(d)(2)	— Supplemental Indenture No. 10 to Exhibit 4(d)(1), dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)	X		X
4(d)(3)	— Supplemental Indenture No. 12 to Exhibit 4(d)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2008	1-31447	4.9	X		X
4(d)(4)	— Supplemental Indenture No. 14 to Exhibit 4(d)(1) dated as of January 11, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021 and 5.85% Senior Notes due 2041	CenterPoint Energy's Form 10-K for the year ended December 31, 2010	1-31447	4(f)(15)	X		X
4(d)(5)	— Supplemental Indenture No. 16 to Exhibit 4(d)(1) dated as of August 23, 2017, providing for the issuance of CERC Corp.'s 4.10% Senior Notes due 2047	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2017	1-31447	4.11	X		X
4(d)(6)	— Supplemental Indenture No. 17 to Exhibit 4(d)(1) dated as of March 28, 2018, providing for the issuance of CERC Corp.'s 3.55% Senior Notes due 2023 and 4.00% Senior Notes due 2028	CERC's Form 10-Q for the quarter ended March 31, 2018	1-13265	4.4	X		X

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(d)(7)	Supplemental Indenture No. 18 to Exhibit 4(d)(1), dated as of October 1, 2020, providing for the issuance of CERC Corp.'s 1.75% Senior Notes due 2030	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2020	1-31447	4.23	X		X
4(d)(8)	Supplemental Indenture No. 21, dated as of June 9, 2022, to the Indenture under Exhibit 4(d)(1)	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2022	1-31447	4.12			X
4(d)(9)	Supplemental Indenture No. 22, to Exhibit 4(d)(1), dated as of October 5, 2022, providing for the issuance of CERC Corp.'s 6.10% Senior Notes due 2035	CERC's Form 8-K dated October 5, 2022	1-13265	4.2			X
4(d)(10)	Supplemental Indenture No. 23 to Exhibit 4(d)(1), dated as of February 23, 2023, providing for the issuance of CERC Corp.'s 5.25% Senior Notes due 2028 and 5.40% Senior Notes due 2033	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2023	1-31447	4.6			X
4(d)(11)	Supplemental Indenture No. 24 to Exhibit 4(d)(1), dated as of May 3, 2023, providing for the issuance of CERC Corp.'s 5.25% Senior Notes due 2028	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2023	1-31447	4.5			X
4(d)(12)	Supplemental Indenture No. 25 to Exhibit 4(d)(1), dated as of June 20, 2024, providing for the issuance of CERC Corp.'s 5.40% Senior Notes due 2034	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2024	1-31447	4.5			X
4(e)(1)	Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.1	X		
4(e)(2)	Supplemental Indenture No. 10 to Exhibit 4(e)(1), dated as of October 5, 2018, providing for the issuance of CenterPoint Energy's 3.60% Senior Notes due 2021, 3.85% Senior Notes due 2024 and 4.25% Senior Notes due 2028	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2018	1-31447	4.14	X		
4(e)(3)	Supplemental Indenture No. 11 to Exhibit 4(e)(1), dated as of August 14, 2019, providing for the issuance of CenterPoint Energy's 2.50% Senior Notes due 2024, 2.95% Senior Notes due 2030 and 3.70% Senior Notes due 2049	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2019	1-31447	4.2	X		
4(e)(4)	Supplemental Indenture No. 13 to Exhibit 4(e)(1), dated as of May 13, 2021, providing for the issuance of CenterPoint Energy's 1.45% Senior Notes due 2026 and 2.65% Senior Notes due 2031	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2021	1-31447	4.25	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(e)(5)	— Supplemental Indenture No. 14 to Exhibit 4(e)(1), dated as of August 10, 2023, providing for the issuance of CenterPoint Energy's 5.25% Senior Notes due 2026	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	4.4	X		
4(e)(6)	— Supplemental Indenture No. 15 to Exhibit 4(e)(1), dated as of May 10, 2024, providing for the issuance of CenterPoint Energy's 5.40% Senior Notes due 2029	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2024	1-31447	4.3	X		
4(f)(1)	— Subordinated Indenture dated as of September 1, 1999	Reliant Energy's Form 8-K dated September 1, 1999	1-3187	4.1	X		
4(f)(2)	— Supplemental Indenture No. 1 dated as of September 1, 1999, between Reliant Energy and Chase Bank of Texas (supplementing Exhibit 4(f)(1) and providing for the issuance Reliant Energy's 2% Zero-Premium Exchangeable Subordinated Notes Due 2029)	Reliant Energy's Form 8-K dated September 15, 1999	1-3187	4.2	X		
4(f)(3)	— Supplemental Indenture No. 2 dated as of August 31, 2002, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(f)(1))	CenterPoint Energy's Form 8-K12B dated August 31, 2002	1-31447	4(e)	X		
4(f)(4)	— Supplemental Indenture No. 3 dated as of December 28, 2005, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(f)(1))	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(h)(4)	X		
4(g)(1)	— Amended and Restated Indenture of Mortgage and Deed of Trust dated as of January 1, 2023, between SIGECO and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 8-K dated January 30, 2023	1-31447	10.2	X		
4(g)(2)	— First Supplemental Indenture to Exhibit 4(g)(1), dated as of March 15, 2023	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	4.2	X		
4(g)(3)	— Second Supplemental Indenture to Exhibit 4(g)(1), dated as of October 13, 2023	CenterPoint Energy's Form 8-K dated October 13, 2023	1-31447	4.2	X		
4(g)(4)	— Third Supplemental Indenture dated as of August 29, 2024, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 8-K dated August 29, 2024	1-31447	4.2	X		
4(g)(5)	— Fourth Supplemental Indenture dated as of January 31, 2025, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 10-K for the year ended December 31, 2024	1-31447	4(g)(5)	X		

<u>Exhibit Number</u>	<u>Description</u>	<u>Report or Registration Statement</u>	<u>SEC File or Registration Number</u>	<u>Exhibit Reference</u>	<u>CenterPoint Energy</u>	<u>Houston Electric</u>	<u>CERC</u>
4(g)(6)	— Fifth Supplemental Indenture dated as of July 1, 2025, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 8-K dated July 1, 2025	1-31447	4.2	X		
4(g)(7)	— Sixth Supplemental Indenture, dated as of October 1, 2025, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2025	1-31447	4.3	X		
4(g)(8)	— Additional Supplemental Indentures to Exhibit 4(g)(1)				X		
		<u>Date as of</u>	<u>File Reference</u>	<u>Exhibit No.</u>			
		July 1, 1999	1-3553, SIGECO's Form 10-Q for the quarter ended June 30, 1999	4(a)			
		April 1, 2013	1-15467, Vectren's Form 8-K dated April 30, 2013	4.1			
		September 1, 2014	1-15467, Vectren's Form 8-K dated September 25, 2014	4.1			
		September 1, 2015	1-15467, Vectren's Form 8-K dated September 10, 2015	4.1			
4(h)(1)	— Indenture dated February 1, 1991 between Indiana Gas Company, Inc. and U.S Bank Trust National Association (formerly known as First Trust National Association, which was formerly known as Bank of America Illinois, which was formerly known as Continental Bank, National Association)	Indiana Gas's Form 8-K filed February 15, 1991	1-6494	4(a)	X		
4(h)(2)	— First Supplemental Indenture to Exhibit 4(h)(1), dated as of February 15, 1991	Indiana Gas's Form 8-K filed February 15, 1991	1-6494	4(b)	X		
4(h)(3)	— Second Supplemental Indenture to Exhibit 4(h)(1), dated as of September 15, 1991	Indiana Gas's Form 8-K filed September 25, 1991	1-6494	4(b)	X		
4(h)(4)	— Third Supplemental Indenture to Exhibit 4(h)(1), dated as of September 15, 1991	Indiana Gas's Form 8-K filed September 25, 1991	1-6494	4(c)	X		
4(h)(5)	— Fourth Supplemental Indenture to Exhibit 4(h)(1), dated as of December 2, 1992	Indiana Gas's Form 8-K filed December 8, 1992	1-6494	4(b)	X		
4(h)(6)	— Fifth Supplemental Indenture to Exhibit 4(h)(1), dated as of December 28, 2000	Indiana Gas's Form 8-K filed December 27, 2000	1-6494	4	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(i)(1)	Bond Purchase and Covenants Agreement, dated September 14, 2017, between SIGECO and PNC Bank, National Association	Vectren's Form 8-K dated September 25, 2017	1-15467	4.1	X		
4(i)(2)	Joinder and First Amendment to Exhibit 4(i)(1) dated March 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association	Vectren's Form 8-K dated May 3, 2018	1-15467	4.1	X		
4(i)(3)	Second Amendment to Exhibit 4(i)(1) dated May 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association	Vectren's Form 8-K dated May 3, 2018	1-15467	4.2	X		
4(i)(4)	Third Amendment to Exhibit 4(i)(1) dated December 7, 2022 among SIGECO, the lenders party thereto and PNC Bank, National Association	CenterPoint Energy's Form 10-K for the year ended December 31, 2022	1-31447	4(k)(4)	X		
4(j)	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of \$40,000,000 aggregate principal amount of CERC's 4.36% Senior Notes, Series B, due December 15, 2045	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.1	X		X
4(k)	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of \$10,000,000 aggregate principal amount of CERC's 4.25% Senior Notes, Series B, due June 5, 2043	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.3	X		X
4(l)	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of \$100,000,000 aggregate principal amount of CERC's 5.00% Senior Notes, due February 3, 2042	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.4	X		X
4(m)	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of \$60,000,000 aggregate principal amount of CERC's 5.02% Senior Notes, Series B, due November 30, 2026 and \$35,000,000 aggregate principal amount of CERC's 5.99% Senior Notes, Series C, due November 30, 2041	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.5	X		X

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(n)	Registration Rights Agreement, dated as of October 5, 2022, between CenterPoint Energy Resources Corp. and Goldman Sachs & Co. LLC	CERC's Form 8-K dated October 5, 2022	1-13265	4.3			X
4(o)	Indenture dated as of August 4, 2023, between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee	CenterPoint Energy's Form 8-K dated August 4, 2023	1-31447	4.1	X		
4(p)(1)	Junior Subordinated Indenture, dated as of August 14, 2024, between CenterPoint Energy, Inc. and The Bank of New York Mellon Trust Company, National Association, as trustee	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2024	1-31447	4.1	X		
4(p)(2)	Supplemental Indenture to Exhibit 4(p)(1), dated as of August 14, 2024	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2024	1-31447	4.2	X		
4(p)(3)	Supplemental Indenture No. 2 to Exhibit 4(p)(1), dated as of October 31, 2024, providing for the issuance of CenterPoint Energy's 6.700% Fixed-to-Fixed Reset Junior Subordinated Notes, Series C, due 2055	CenterPoint Energy's Form 10-K for the year ended December 31, 2024	1-31447	4(p)(3)	X		
4(p)(4)	Supplemental Indenture No. 3 to Exhibit 4(p)(1), dated as of October 2, 2025, providing for the issuance of CenterPoint Energy's 5.950% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series D, due 2056	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2025	1-31447	4.6	X		
4(q)	Indenture dated as of July 31, 2025, between CenterPoint Energy, Inc. and The Bank of New York Mellon Trust Company, National Association, as trustee	CenterPoint Energy's Form 8-K dated July 31, 2025	1-31447	4.1	X		
4(r)	Indenture by and among CenterPoint Energy Restoration Bond Company II, LLC, U.S. Bank Trust Company, National Association, as Indenture Trustee, and U.S. Bank National Association, as Securities Intermediary (including the forms of the System Restoration Bonds and the form of Series Supplement), dated as of September 17, 2025	Houston Electric's Form 8-K dated September 17, 2025	1-3187	4.1		X	
4(s)	Series Supplement by and between CenterPoint Energy Restoration Bond Company II, LLC and U.S. Bank Trust Company, National Association, as Indenture Trustee, dated as of September 17, 2025	Houston Electric's Form 8-K dated September 17, 2025	1-3187	4.2		X	
4(t)	Description of CenterPoint Energy's Securities				X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
†4(u)	— Description of Houston Electric's Securities					X	
†4(v)	— Description of CERC's Securities						X

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the Registrants have not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of the Registrants and its subsidiaries on a consolidated basis. The Registrants hereby agree to furnish a copy of any such instrument to the SEC upon request.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(a)	— CenterPoint Energy, Inc. 1991 Benefit Restoration Plan, as amended and restated effective as of February 25, 2011	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2011	1-31447	10.3	X		
*10(b)(1)	— CenterPoint Energy Benefit Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.1	X		
*10(b)(2)	— First Amendment to Exhibit 10(b)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.4	X		
*10(b)(3)	— Partial Termination Amendment to Exhibit 10(b)(1), effective as of March 1, 2022	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022	1-31447	10.14	X		
*10(b)(4)	— Third Amendment to Exhibit 10(b)(1), effective as of October 1, 2023	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended September 30, 2023	1-31447	10.2	X		
*10(c)	— CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1	X		
*10(d)(1)	— Amended and Restated CenterPoint Energy, Inc. 1991 Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.4	X		
*10(d)(2)	— First Amendment to Exhibit 10(d)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.5	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(e)(1)	— CenterPoint Energy Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.3	X		
*10(e)(2)	— First Amendment to Exhibit 10(e)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.6	X		
*10(e)(3)	— Second Amendment to Exhibit 10(e)(1), effective as of January 1, 2020	CenterPoint Energy's Form 8-K dated December 9, 2019	1-31447	10.1	X		
*10(e)(4)	— Partial Termination Amendment to Exhibit 10(e)(1), effective as of March 1, 2022	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022	1-31447	10.18	X		
*10(e)(5)	— Fourth Amendment to Exhibit 10(e)(1), effective as of October 1, 2023	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended September 30, 2023	1-31447	10.3	X		
*10(e)(6)	— Fifth Amendment to Exhibit 10(e)(1), effective as of January 1, 2024	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(e)(6)	X		
*10(e)(7)	— Partial Termination Amendment to Exhibit 10(e)(1), effective as of April 1, 2024	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(e)(7)	X		
*10(f)	— CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5	X		
10(g)(1)	— Stockholder's Agreement dated as of July 6, 1995 between Houston Industries Incorporated and Time Warner Inc.	Schedule 13-D dated July 6, 1995	5-19351	2	X		
10(g)(2)	— Amendment to Exhibit 10(g)(1) dated November 18, 1996	HI's Form 10-K for the year ended December 31, 1996	1-7629	10(x)(4)	X		
10(h)(1)	— Master Separation Agreement entered into as of December 31, 2000 between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(h)(2)	— First Amendment to Exhibit 10(h)(1) effective as of February 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(bb)(5)	X		
10(h)(3)	— Employee Matters Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.5	X		
10(h)(4)	— Retail Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.6	X		
10(h)(5)	— Tax Allocation Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8	X		
10(i)(1)	— Separation Agreement entered into as of August 31, 2002 between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(1)	X		
10(i)(2)	— Transition Services Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(2)	X		
10(i)(3)	— Tax Allocation Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(3)	X		
*10(j)(1)	— CenterPoint Energy, Inc. Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2003	1-31447	10.2	X		
*10(j)(2)	— First Amendment to Exhibit 10(j)(1) effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.4	X		
*10(k)(1)	— Amended and Restated CenterPoint Energy 2005 Deferred Compensation Plan, effective January 1, 2009	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.1	X		
*10(k)(2)	— First Amendment to Exhibit 10(k)(1) effective March 1, 2022	CenterPoint Energy's Form 8-K dated April 22, 2022	1-31447	10.10	X		
*10(k)(3)	— Second Amendment to Exhibit 10(k)(1) effective May 1, 2022	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2022	1-31447	10.11	X		
*10(k)(4)	— Third Amendment to Exhibit 10(k)(1) effective October 1, 2023	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	10.1	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(k)(5)	— Partial Termination Amendment to Exhibit 10(k)(1) effective April 1, 2024	CenterPoint Energy Form 10-K for the year ended December 31, 2023	1-31447	10(1)	X		
*10(k)(6)	— Fifth Amendment to Exhibit 10(k)(1) effective January 1, 2026	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2025	1-31447	10.4	X		
*10(l)(1)	— CenterPoint Energy Inc., Short Term Incentive Plan, as amended and restated effective January 1, 2022	CenterPoint Energy Form 10-K for the year ended December 31, 2021	1-31447	10(1)	X		
*10(l)(2)	— First Amendment to Exhibit 10(l)(1) effective as of January 1, 2023	CenterPoint Energy Form 10-K for the year ended December 31, 2022	1-31447	10(1)(2)	X		
*10(m)(1)	— Amended and Restated CenterPoint Energy Stock Plan for Outside Directors	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2018	1-31447	10.1	X		
*10(m)(2)	— First Amendment to Exhibit 10(m)(1), dated as of February 19, 2020	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(n)(2)	X		
*10(m)(3)	— Second Amendment to Exhibit 10(m)(1), dated as of February 14, 2025	CenterPoint Energy's Form 10-K for the year ended December 31, 2024	1-31447	10(m)(2)	X		
10(n)	— City of Houston Franchise Ordinance	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2005	1-31447	10.1	X	X	
10(o)(1)	— Amended and Restated HL&P Executive Incentive Compensation Plan effective as of January 1, 1985	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.2	X		
10(o)(2)	— First Amendment to Exhibit 10(o)(1) effective as of January 1, 2008	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.3	X		
*10(p)(1)	— CenterPoint Energy, Inc. 2009 Long Term Incentive Plan	CenterPoint Energy's Schedule 14A dated March 13, 2009	1-31447	A	X		
*10(p)(2)	— Form of Performance Award Agreement for 20XX - 20XX Performance Cycle under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(q)(2)	X		
*10(p)(3)	— Form of Restricted Stock Unit Award Agreement (Service-Based Vesting) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(q)(5)	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(p)(4)	— Form of Restricted Stock Unit Award Agreement (Retention, Service-Based Vesting) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.4	X		
*10(p)(5)	— Form of Performance Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.2	X		
*10(p)(6)	— Form of Restricted Stock Unit Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.3	X		
*10(p)(7)	— Form of Award Agreement for Performance Share Units for Named Executive Officers (Separation) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated June 30, 2020	1-31447	10.1	X		
*10(p)(8)	— Form of Award Agreement for Restricted Stock Units for Named Executive Officers (Separation) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated June 30, 2020	1-31447	10.2	X		
*10(p)(9)	— Form of Restricted Stock Unit Award Agreement (Service-Based Vesting with Performance Goals) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(q)(12)	X		
*10(p)(10)	— Form of Restricted Stock Unit Award Agreement for CEO (Service-Based Vesting with Performance Goals) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(q)(13)	X		
*10(p)(11)	— Form of Restricted Stock Unit Award Agreement (Fully Vested) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated February 19, 2020	1-31447	10.1	X		
*10(p)(12)	— Form of Restricted Stock Unit Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated July 20, 2021	1-31447	10.1	X		
*10(q)(1)	— CenterPoint Energy, Inc. Change in Control Plan, as amended and restated effective May 1, 2017	CenterPoint Energy's Form 8-K dated April 27, 2017	1-31447	10.1	X		
*10(q)(2)	— First Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(t)(2)	X		
*10(q)(3)	— Second Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2021	1-31447	10(q)(3)	X		
*10(q)(4)	— Third Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	10.1	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(r)	— Omnibus Amendment to CenterPoint Energy, Inc. Benefit Plans, dated May 23, 2013	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(zz)	X		
*10(s)(1)	— Vectren Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001	Vectren's Form 10-K for the year end December 31, 2001	1-15467	10.32	X		
*10(s)(2)	— July 1, 2002 Amendment to Exhibit 10(s)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2023	1-31447	10(s)(2)	X		
*10(t)(1)	— Vectren Corporation Non-Qualified Deferred Compensation Plan, effective January 1, 2005	Vectren's Form 8-K dated September 29, 2008	1-15467	10.3	X		
*10(t)(2)	— Partial Termination Amendment to Exhibit 10(t)(1), effective as of January 1, 2005	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	10.2	X		
*10(u)(1)	— Vectren Nonqualified Defined Benefit Restoration Plan, as amended and restated effective January 1, 2005	Vectren's Form 8-K dated December 17, 2008	1-15467	10.2	X		
*10(u)(2)	— First Amendment to Exhibit 10(u)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2023	1-31447	10(u)(2)	X		
*10(v)	— Vectren Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005)	Vectren's Form 8-K dated December 17, 2008	1-15467	10.1	X		
*10(w)	— Vectren Specimen Waiver, effective October 3, 2013, to the Vectren Unfunded Supplemental Retirement Plan for a Select Group of Management Employees	Vectren's Form 10-Q for the quarter ended September 30, 2013	1-15467	10.1	X		
*10(x)(1)	— CenterPoint Energy, Inc. 2022 Long Term Incentive Plan	CenterPoint Energy's Definitive Proxy Statement filed on March 11, 2022	1-31447	Appendix A	X		
*10(x)(2)	— Form of Performance Award Agreement for 20XX-20XX Performance Cycle for the CEO under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.2	X		
*10(x)(3)	— Form of Performance Award Agreement for 20XX-20XX Performance Cycle for officers and director employees under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.3	X		
*10(x)(4)	— Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.4	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(x)(5)	— Form of Restricted Stock Unit Award Agreement for the CEO (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.5	X		
*10(x)(6)	— Form of Restricted Stock Unit Award Agreement for Officers and Director Employees (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.7	X		
*10(x)(7)	— Form of Restricted Stock Unit Award Agreement for the CEO under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.8	X		
*10(x)(8)	— Form of Performance Award Agreement for the President and Chief Operating Officer under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2022	1-31447	10(cc)(9)	X		
*10(x)(9)	— Form of Restricted Stock Unit Award Agreement for President and Chief Operating Officer (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2022	1-31447	10(cc)(10)	X		
*10(x)(10)	— Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.2	X		
*10(x)(11)	— Form of Award Agreement for Performance Share Units for Officer and Director Employees under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated September 27, 2023	1-31447	10.1	X		
*10(x)(12)	— Form of Award Agreement for Restricted Stock Units for Officer and Director under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated September 27, 2023	1-31447	10.2	X		
*10(x)(13)	— Form of Restricted Stock Unit Award Agreement for Officers and Director Employees (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(13)	X		
*10(x)(14)	— Form of Performance Award Agreement for Officers and Director Employees under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(14)	X		
*10(x)(15)	— Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(15)	X		
†*10(x)(16)	— Form of Performance Award Agreement for Chair of Board, President & Chief Executive Officer under Exhibit 10(x)(1)				X		
†*10(x)(17)	— Form of Restricted Stock Unit Award Agreement for Chair of Board, President & Chief Executive Officer under Exhibit 10(x)(1)				X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(y)(1)	— \$2,400,000,000 Amended and Restated Credit Agreement dated as of December 6, 2022 among CenterPoint Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.1	X		
10(y)(2)	— First Amendment to Exhibit 10(y)(1), dated as of July 26, 2023	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2023	1-31447	10.1	X		
10(y)(3)	— Extension Agreement to Exhibit 10(y)(1), dated as of January 29, 2025	CenterPoint Energy's Form 8-K dated January 29, 2025	1-31447	10.1	X		
10(z)(1)	— \$300,000,000 Credit Agreement dated as of December 6, 2022 among CenterPoint Energy, Houston Electric, LLC, as Borrower, Mizuho Bank, Ltd., as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.2		X	
10(z)(2)	— Extension Agreement to Exhibit 10(z)(1), dated as of January 29, 2025	CenterPoint Energy's Form 8-K dated January 29, 2025	1-31447	10.2		X	
10(aa)(1)	— \$1,050,000,000 Credit Agreement dated as of December 6, 2022 among CenterPoint Energy, Resources Corp., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.3			X
10(aa)(2)	— Extension Agreement to Exhibit 10(aa)(1), dated as of January 29, 2025	CenterPoint Energy's Form 8-K dated January 29, 2025	1-31447	10.3			X
10(bb)(1)	— \$250,000,000 Credit Agreement dated as of December 6, 2022 among Southern Indiana Gas and Electric Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.4	X		
10(bb)(2)	— Extension Agreement to Exhibit 10(bb)(1), dated as of January 29, 2025	CenterPoint Energy's Form 8-K dated January 29, 2025	1-31447	10.4	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(cc)(1)	— Term Loan Agreement dated as of June 24, 2024 among CenterPoint Energy Houston Electric, LLC as borrower, Mizuho Bank, Ltd., as administrative agent, and the banks party thereto	CenterPoint Energy's Form 8-K dated June 24, 2024	1-31447	10.1		X	
10(cc)(2)	— First Amendment to Exhibit 10(cc)(1), dated as of November 20, 2025	Houston Electric's Form 8-K dated November 20, 2025	1-3187	10.2		X	
*10(dd)	— Christopher A. Foster Offer Letter	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.1	X		
10(ee)	— Bond Purchase Agreement dated March 15, 2023 among SIGECO and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.1	X		
10(ff)	— Bond Purchase Agreement dated October 13, 2023 among SIGECO and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated October 13, 2023	1-31447	10.1	X		
10(gg)	— Bond Purchase Agreement dated August 29, 2024 among Southern Indiana Gas and Electric Company and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated August 29, 2024	1-31447	10.1	X		
10(hh)	— Bond Purchase Agreement dated July 1, 2025 among Southern Indiana Gas and Electric Company and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated July 1, 2025	1-31447	10.1	X		
10(ii)	— Equity Distribution Agreement, dated January 10, 2024, among CenterPoint Energy, Inc. and BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC, as managers, Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., Goldman Sachs & Co. LLC, JPMorgan Chase Bank, National Association, Mizuho Markets Americas LLC, MUFG Securities EMEA plc and Royal Bank of Canada, as forward purchasers, and BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC, as forward sellers	CenterPoint Energy's Form 8-K dated January 10, 2024	1-31447	1.1	X		

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(jj)	— Confirmation of Forward Sale Transaction, dated May 27, 2025, between CenterPoint Energy, Inc. and Bank of America, N.A., in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 28, 2025	1-31447	10.1	X		
10(kk)	— Confirmation of Forward Sale Transaction, dated May 27, 2025, between CenterPoint Energy, Inc. and Mizuho Markets Americas LLC (with Mizuho Securities USA LLC acting as agent), in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 28, 2025	1-31447	10.2	X		
10(ll)	— Confirmation of Forward Sale Transaction, dated May 27, 2025, between CenterPoint Energy, Inc. and JPMorgan Chase Bank, National Association, in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 28, 2025	1-31447	10.3	X		
10(mm)	— Confirmation of Forward Sale Transaction, dated May 28, 2025, between CenterPoint Energy, Inc. and Bank of America, N.A., in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 29, 2025	1-31447	10.1	X		
10(nn)	— Confirmation of Forward Sale Transaction, dated May 28, 2025, between CenterPoint Energy, Inc. and Mizuho Markets Americas LLC (with Mizuho Securities USA LLC acting as agent), in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 29, 2025	1-31447	10.2	X		
10(oo)	— Confirmation of Forward Sale Transaction, dated May 28, 2025, between CenterPoint Energy, Inc. and JPMorgan Chase Bank, National Association, in its capacity as a forward purchaser	CenterPoint Energy's Form 8-K dated May 29, 2025	1-31447	10.3	X		
*10(pp)	— Jesus Soto, Jr. Offer Letter	CenterPoint Energy's Form 8-K dated July 21, 2025	1-31447	10.1	X		
19	— Insider Trading Policy	CenterPoint Energy's 10-K for the year ended December 31, 2024	1-31447	19	X		
†21.1	— Subsidiaries of CenterPoint Energy				X		
†21.2	— Subsidiaries of CERC Corp.						X
†23.1.1	— Consent of Deloitte & Touche LLP				X		
†23.1.2	— Consent of Deloitte & Touche LLP					X	
†23.1.3	— Consent of Deloitte & Touche LLP						X
†31.1.1	— Rule 13a-14(a)/15d-14(a) Certification of Jason P. Wells				X		
†31.1.2	— Rule 13a-14(a)/15d-14(a) Certification of Jesus Soto, Jr.					X	
†31.1.3	— Rule 13a-14(a)/15d-14(a) Certification of Jesus Soto, Jr.						X

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
†31.2.1	— Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster				X		
†31.2.2	— Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster					X	
†31.2.3	— Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster						X
†32.1.1	— Section 1350 Certification of Jason P. Wells				X		
†32.1.2	— Section 1350 Certification of Jesus Soto, Jr.					X	
†32.1.3	— Section 1350 Certification of Jesus Soto, Jr.						X
†32.2.1	— Section 1350 Certification of Christopher A. Foster				X		
†32.2.2	— Section 1350 Certification of Christopher A. Foster					X	
†32.2.3	— Section 1350 Certification of Christopher A. Foster						X
†97.1	— CenterPoint Energy's Executive Officer Recovery Policy				X		
†97.2	— Houston Electric's Amended and Restated Executive Officer Recovery Policy					X	
†97.3	— CERC's Amended and Restated Executive Officer Recovery Policy						X
†101.INS	— Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document				X	X	X
†101.SCH	— Inline XBRL Taxonomy Extension Schema Document				X	X	X
†101.CAL	— Inline XBRL Taxonomy Extension Calculation Linkbase Document				X	X	X
†101.DEF	— Inline XBRL Taxonomy Extension Definition Linkbase Document				X	X	X
†101.LAB	— Inline XBRL Taxonomy Extension Labels Linkbase Document				X	X	X
†101.PRE	— Inline XBRL Taxonomy Extension Presentation Linkbase Document				X	X	X
†104	— Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)				X	X	X

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 19th day of February, 2026.

CENTERPOINT ENERGY, INC.
(Registrant)

By: /s/ JASON P. WELLS
Jason P. Wells

Chair of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 19, 2026.

<u>Signature</u>	<u>Title</u>
<u>/s/ JASON P. WELLS</u> Jason P. Wells	Chair of the Board, President and Chief Executive Officer (Principal Executive Officer and Director)
<u>/s/ CHRISTOPHER A. FOSTER</u> Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
<u>/s/ KRISTIE L. COLVIN</u> Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)
<u>/s/ WENDOLYNN MONTOYA CLOONAN</u> Wendolynn Montoya Cloonan	Director
<u>/s/ BARBARA J. DUGANIER</u> Barbara J. Duganier	Director
<u>/s/ LAURIE L. FITCH</u> Laurie L. Fitch	Director
<u>/s/ CHRISTOPHER H. FRANKLIN</u> Christopher H. Franklin	Director
<u>/s/ RAQUELLE W. LEWIS</u> Raquelle W. Lewis	Director
<u>/s/ THADDEUS J. MALIK</u> Thaddeus J. Malik	Director
<u>/s/ MANUEL B. MIRANDA</u> Manuel B. Miranda	Director
<u>/s/ THEODORE F. POUND</u> Theodore F. Pound	Director
<u>/s/ DEAN L. SEAVERS</u> Dean L. Seavers	Director
<u>/s/ PHILLIP R. SMITH</u> Phillip R. Smith	Director

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
(Registrant)

By: _____ */s/ JESUS SOTO, JR.*
Jesus Soto, Jr.
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 19, 2026.

Signature	Title
_____ <i>/s/ JESUS SOTO, JR.</i> Jesus Soto, Jr.	President and Chief Executive Officer (Principal Executive Officer)
_____ <i>/s/ CHRISTOPHER A. FOSTER</i> Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
_____ <i>/s/ KRISTIE L. COLVIN</i> Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP.
(Registrant)

By: _____ */s/ JESUS SOTO, JR.*
Jesus Soto, Jr.
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 19, 2026.

Signature	Title
_____ <i>/s/ JESUS SOTO, JR.</i> Jesus Soto, Jr.	President and Chief Executive Officer (Principal Executive Officer and Director)
_____ <i>/s/ CHRISTOPHER A. FOSTER</i> Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
_____ <i>/s/ KRISTIE L. COLVIN</i> Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)

**DESCRIPTION OF CENTERPOINT ENERGY, INC.'S SECURITIES
REGISTERED PURSUANT TO SECTION 12
OF THE SECURITIES EXCHANGE ACT OF 1934**

As of December 31, 2025, CenterPoint Energy, Inc. has one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) our common stock, par value \$0.01 per share. As used in this Exhibit 4(t), the terms "CenterPoint Energy," "us," "we" or "our" refer to CenterPoint Energy, Inc. and not any of its subsidiaries.

CenterPoint Energy, Inc. is authorized to issue up to 1,000,000,000 shares of common stock, par value \$0.01 per share, and 20,000,000 shares of preferred stock, par value \$0.01 per share.

DESCRIPTION OF OUR COMMON STOCK

The following description of our common stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Restated Articles of Incorporation ("Articles of Incorporation") and Fifth Amended and Restated Bylaws ("Bylaws"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4(t) is a part. We encourage you to read our Articles of Incorporation, our Bylaws and the applicable provisions of the Texas Business Organizations Code ("TBOC") for additional information.

Voting Rights. Holders of our common stock are entitled to one vote for each share on all matters submitted to a vote of shareholders, including the election of directors. There are no cumulative voting rights. Subject to the voting rights expressly conferred to the holders of our preferred stock, the holders of our common stock possess exclusive full voting power for the election of directors and for all other purposes. Our Bylaws provide that, in an uncontested election, director nominees are elected by the vote of a majority of the votes cast with respect to the director by shareholders entitled to vote in the election of directors at a meeting of shareholders at which a quorum is present. An election is contested if, (x) the secretary receives notice that one or more shareholders has proposed to nominate one or more persons for election or re-election to the board of directors, which notice purports to be in compliance with the advance notice requirements for shareholder nominations set forth in the Bylaws, irrespective of whether the board of directors at any time determines that any such notice is not in compliance with such requirements, and (y) such nomination or nominations have not been formally and irrevocably withdrawn by such shareholder(s) on or prior to the date that is 14 days in advance of the date we file our definitive proxy statement with the Securities and Exchange Commission, in which case directors will be elected by the vote of a plurality of the votes cast by shareholders entitled to vote in the election of directors at a meeting of shareholders at which a quorum is present.

Dividends. Subject to preferences that may be applicable to any of our outstanding preferred stock, the holders of our common stock are entitled to dividends when, as and if declared by the board of directors out of funds legally available for that purpose.

Liquidation Rights. If we are liquidated, terminated or wound up, the holders of our common stock will be entitled to a pro rata share in any distribution to shareholders, but only after satisfaction of all of our liabilities and of

the prior rights of any outstanding class of our preferred stock, which may include the right to participate further with the holders of our common stock in the distribution of any of our remaining assets.

Preemptive Rights. Holders of our common stock are not entitled to any preemptive or conversion rights or other subscription rights.

Transfer Agent and Registrar. Broadridge Corporate Issuer Solutions, Inc. serves as transfer agent and registrar for our common stock.

Other Provisions. There are no redemption or sinking fund provisions applicable to our common stock. No personal liability will attach to holders of such shares under the laws of the State of Texas. Subject to the provisions of our Articles of Incorporation and Bylaws imposing certain supermajority voting provisions, the rights of the holders of shares of our common stock may not be modified except by a vote of at least a majority of the shares outstanding entitled to vote thereon, voting together as a single class.

Preferred Stock

Our board of directors may cause us to issue preferred stock from time to time in one or more series and may fix the number of shares and the terms of each series without the approval of our shareholders. Our board of directors may determine the terms of each series, including:

- the designation of the series,
- dividend rates and payment dates,
- whether dividends will be cumulative, non-cumulative or partially cumulative, and related terms,
- redemption rights,
- liquidation rights,
- sinking fund provisions,
- conversion rights,
- voting rights, and
- any other terms.

The statement of resolutions establishing any series of preferred stock will include specific terms relating to such series of preferred stock. We will file the statement of resolutions with the Texas Secretary of State before we issue any of it. The statement of resolutions establishing a series of preferred stock will include some or all of the following terms:

- the title of the preferred stock,
- the maximum number of shares of the series,

- the dividend rate or the method of calculating the dividend, the date from which dividends will accrue and whether dividends will be cumulative.
- any liquidation preference,
- any optional redemption provisions,
- any sinking fund or other provisions that would obligate us to redeem or purchase the preferred stock,
- any terms for the conversion or exchange of the preferred stock for other securities of us or any other entity,
- any voting rights, and
- any other preferences and relative, participating, optional or other special rights or any qualifications, limitations or restrictions on the rights of the shares.

The issuance of preferred stock, while providing desired flexibility in connection with possible acquisitions and other corporate purposes, could adversely affect the voting power of holders of our common stock. It could also affect the likelihood that holders of our common stock will receive dividend payments and payments upon liquidation. The issuance of shares of preferred stock, or the issuance of rights to purchase shares of preferred stock, could be used to discourage an attempt to obtain control of us. For example, if, in the exercise of its fiduciary obligations, our board were to determine that a takeover proposal was not in our best interest, the board could authorize the issuance of a series of preferred stock containing class voting rights that would enable the holder or holders of the series to prevent or make the change of control transaction more difficult. Alternatively, a change of control transaction deemed by the board to be in our best interest could be facilitated by issuing a series of preferred stock having sufficient voting rights to provide a required percentage vote of the shareholders.

Anti-Takeover Effects of Texas Laws and Our Charter and Bylaw Provisions

Some provisions of Texas law and our Articles of Incorporation and Bylaws could make the following actions more difficult:

- acquisition of us by means of a tender offer,
- acquisition of control of us by means of a proxy contest or otherwise, or
- removal of our incumbent officers and directors.

These provisions are designed to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of this increased protection gives us the potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us, and that the benefits of this increased protection outweigh the disadvantages of discouraging those proposals, because negotiation of those proposals could result in an improvement of their terms.

Charter and Bylaw Provisions

Election and Removal of Directors. The number of members of our board of directors will be fixed from time to time by resolution of the board of directors. Except for voting rights as may be provided to holders of preferred stock, at each annual meeting of shareholders, all directors are elected to hold office for a term expiring at the next succeeding annual meeting of shareholders and until their successors have been elected and qualified.

No director may be removed except for cause, and, subject to the voting rights expressly conferred to the holders of our preferred stock, directors may be removed for cause only by the holders of at least a majority of the voting power of all outstanding shares of capital stock entitled to vote in an election of directors. Subject to the voting rights expressly conferred to the holders of our preferred stock, any vacancy occurring on the board of directors and any newly created directorship may be filled by the affirmative vote of a majority of the remaining directors in office or by election by the shareholders.

Shareholder Meetings. Our Articles of Incorporation and Bylaws provide that special meetings of holders of common stock may be called only by the chair of our board of directors, our chief executive officer, the president, the secretary, a majority of our board of directors or the holders of at least 50% of the shares of our capital stock outstanding and entitled to vote at the meeting.

Modification of Articles of Incorporation. In general, amendments to our Articles of Incorporation that are recommended by the board of directors require the affirmative vote of holders of at least a majority of the outstanding shares of capital stock entitled to vote thereon. The provisions described above under “— Election and Removal of Directors” and “— Shareholder Meetings” may be amended only by the affirmative vote of holders of at least 66 2/3% of the voting power of all outstanding shares of capital stock entitled to vote in the election of directors. The provisions described below under “— Modification of Bylaws” may be amended only by the affirmative vote of holders of at least 80% of the voting power of all outstanding shares of capital stock entitled to vote in the election of directors.

Modification of Bylaws. Our board of directors has the power to alter, amend or repeal the Bylaws or adopt new Bylaws by the affirmative vote of at least 80% of all directors then in office at any regular or special meeting of the board of directors. The shareholders also have the power to alter, amend or repeal the Bylaws or adopt new Bylaws by the affirmative vote of holders of at least 80% of the voting power of all outstanding shares of capital stock entitled to vote in the election of directors, voting together as a single class.

Other Limitations on Shareholder Actions. Our Bylaws also impose some procedural requirements on shareholders who wish to:

- make nominations in the election of directors,
- propose that a director be removed,
- propose any repeal or change in the Bylaws, or
- propose any other business to be brought before an annual or special meeting of shareholders.

Under these procedural requirements, a shareholder must deliver timely notice in proper written form (as specified in the Bylaws) to our secretary of the nomination or proposal along with evidence of, among other things:

- the shareholder's status as a shareholder,
- the number of shares beneficially owned by the shareholder,
- a list of the persons with whom the shareholder is acting in concert, and
- the number of shares such persons beneficially own.

To be timely, a shareholder must deliver the notice:

- in connection with an annual meeting of shareholders, not later than the close of business on the 90th day nor earlier than the close of business on the 180th day prior to the first anniversary of the date on which the immediately preceding year's annual meeting of shareholders was held; provided that if the date of the annual meeting is advanced by more than 30 days prior to or delayed by more than 60 days after the first anniversary of the preceding year's annual meeting of shareholders, not earlier than the close of business 180 days prior to the annual meeting and not later than the last to occur of the close of business (i) the 90th day prior to the annual meeting or (ii) the 10th day following the day on which we first make public
- in connection with the nomination of director candidates at a special meeting of shareholders, generally not later than the close of business on the 40th day nor earlier than the close of business on the 60th day prior to the date of the special meeting

To submit a nomination for the board of directors, a shareholder must also submit information with respect to the nominee that we would be required to include in a proxy statement, and, with respect to a nomination for an annual meeting, reasonable evidence that it has complied with the requirements of Rule 14a-19 of the Exchange Act not later than eight business days prior to the date of the meeting, as well as certain other information relating to the candidate's eligibility, including any required updates or supplements to such information as of the record date for the meeting and as of the date that is ten business days prior to the meeting. If a shareholder fails to follow the required procedures, the shareholder's nominee or proposal will be ineligible and will not be voted on by our shareholders.

In addition to the director nomination provisions described above, our Bylaws contain a "proxy access" provision that provides that any shareholder or group of up to twenty shareholders who have owned 3% or more of our outstanding capital stock continuously for at least three years to nominate and include in our proxy materials for an annual meeting of shareholders, director candidates constituting up to 20% of our board of directors or two directors, whichever is greater, provided that the shareholder (or group) and each nominee satisfy the eligibility requirements specified in our Bylaws. An eligible shareholder (or group) proposing to nominate a person for election to our board of directors through the proxy access provision must provide us with a notice requesting the inclusion of the director nominee in our proxy materials and other required information not less than 120 days nor more than 150 days prior to the first anniversary of the date on which the immediately preceding year's annual meeting of shareholders was held. In addition, an eligible shareholder (or group) may include a written statement of not more than 500 words supporting the candidacy of such shareholder nominee. The complete proxy access provision for director nominations are set forth in our Bylaws.

In connection with a special meeting of shareholders, the only business that will be conducted is that stated in the notice of special meeting, or otherwise properly brought and made in proper written form before the meeting by or at the direction of the Chair of the Meeting or the board of directors. Shareholders requesting a special meeting are permitted to make proposals for matters to be brought before the meeting in their request.

Limitation on Liability of Directors. Our Articles of Incorporation provide that no director will be personally liable to us or our shareholders for monetary damages for breach of fiduciary duty as a director, except as required by law as in effect from time to time. Currently, Texas law requires that liability be imposed for the following actions:

- any breach of the director’s duty of loyalty to us or our shareholders,
- any act or omission not in good faith that constitutes a breach of duty of the director to the corporation or that involves intentional misconduct or a knowing violation of law.
- a transaction from which the director received an improper benefit, regardless of whether or not the benefit resulted from an action taken within the scope of a director’s duties, and
- an act or omission for which the liability of a director is expressly provided for by statute.

Our Bylaws provide that we will indemnify our current or former officers and directors and advance expenses to them in connection with proceedings and claims, to the fullest extent permitted by the TBOC. The Bylaws authorize our board of directors to indemnify and advance expenses to people other than our current or former officers and directors in certain circumstances.

Choice of Forum

Our Bylaws provide that, unless we consent to the selection of an alternative forum, the United States District Court for the Southern District of Texas or, if such court lacks jurisdiction, the Eleventh Business Court Division of the Texas Business Court, located in Harris County, Texas, shall be the sole and exclusive forum for certain actions brought on behalf of the company or asserting claims against the company or its directors, officers or employees. Our Bylaws also provide that the federal district courts of the United States will be the sole and exclusive forum for claims arising under the Securities Act of 1933, as amended.

Shareholder Derivative Proceedings

As permitted by the TBOC, our Bylaws provide that no shareholder (as defined in Section 21.551(2) of the TBOC) or group of such shareholders may institute or maintain a derivative proceeding brought on behalf of the Company against any director and/or officer of the Company in such person’s official capacity unless the shareholder or group of shareholders, at the time the derivative proceeding is instituted, beneficially owns a number of shares of our common stock sufficient to meet an ownership threshold of at least 3% of the outstanding shares of our common stock.

Jury Trial Waiver

As permitted by the TBOC, our Bylaws provide that, unless we consent in writing to a jury trial, the Company and each shareholder, director, and officer of the Company irrevocably and unconditionally waives any right that such person or entity may have to a trial by jury in any legal action, proceeding, cause of action, counterclaim, cross-claim, or third-party claim arising out of or relating to any “internal entity claim” under the TBOC, and each shareholder agrees that their holding or acquisition of shares of capital stock of the Company or, to the extent permitted by law, options or rights to acquire shares of capital stock of the Company, constitutes such shareholder’s intentional and knowing waiver of any right to trial by jury with respect to such claim.

Texas Anti-Takeover Law

We are subject to Section 21.606 of the TBOC. That section prohibits Texas public corporations from engaging in a wide range of specified transactions with any affiliated shareholder during the three-year period immediately following the affiliated shareholder's acquisition of shares in the absence of certain board of director or shareholder approvals. An affiliated shareholder of a corporation is any person, other than the corporation and any of its wholly owned subsidiaries, that is or was within the preceding three-year period the beneficial owner of 20% or more of the outstanding shares of stock entitled to vote generally in the election of directors. Section 21.606 may deter any potential unfriendly offers or other efforts to obtain control of us that are not approved by our board of directors. This may deprive our shareholders of opportunities to sell shares of our common stock at a premium to the prevailing market price.

Listing. Our common stock is traded on the New York Stock Exchange and the NYSE Texas under the trading symbol "CNP."

**DESCRIPTION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC'S SECURITIES
REGISTERED PURSUANT TO SECTION 12
OF THE SECURITIES EXCHANGE ACT OF 1934**

As of December 31, 2025, CenterPoint Energy Houston Electric, LLC has one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) our 6.95% general mortgage bonds due 2033 ("General Mortgage Bonds"). As used in this Exhibit 4(u), the terms "CenterPoint Energy Houston Electric, LLC," "us," "we" or "our" refer to CenterPoint Energy Houston Electric, LLC and not any of its subsidiaries.

DESCRIPTION OF OUR GENERAL MORTGAGE BONDS

The following description of our General Mortgage Bonds is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our General Mortgage Indenture dated as of October 10, 2002 with The Bank of New York Mellon Trust Company, N.A. (successor in trust to JPMorgan Chase Bank), as trustee, as amended and supplemented, in the case of the General Mortgage Bonds, by the Tenth Supplemental Indenture, dated as of March 18, 2003, each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4(u) is a part. We encourage you to read the above referenced General Mortgage Indenture and Tenth Supplemental Indenture for additional information.

General

The bonds were issued under the General Mortgage Indenture (the "indenture"), dated as of October 10, 2002, between us and JPMorgan Chase Bank, as trustee (the "trustee"), as amended and supplemented. The descriptions under this heading and the heading "The Indenture" are summaries of the material provisions of the bonds and the indenture. Such summaries do not purport to be complete and are qualified in their entirety by reference to the indenture and the bonds. References to article and section numbers in this offering memorandum, unless otherwise indicated, are references to article and section numbers of the indenture.

The bonds will bear interest at the rate of 6.95% per annum. Interest on the bonds is payable semi-annually in arrears on each March 15 and September 15 (each an "interest payment date"), commencing September 15, 2003, to the persons in whose names they are registered at the close of business on the fifteenth calendar day preceding each interest payment date; provided, however, that interest payable at maturity (whether at stated maturity, upon redemption or otherwise) will be payable to the registered bondholder to whom principal is payable.

The bonds mature on March 15, 2033. The bonds are subject to optional redemption before their maturity as described below. They are not entitled to the benefit of any sinking fund.

Interest

Interest on the bonds will be payable on each interest payment date for the period commencing on the next preceding interest payment date (or if no interest has been paid thereon, commencing on the date of issuance thereof) to, but not including, such interest payment date.

If any interest payment date or the date of maturity falls on a day that is not a business day, all payments to be made on such day shall be made on the next succeeding business day with the same force and effect as if made on the due date, and no additional interest shall be payable as a result of such delay in payment. Interest will be computed on the basis of a 360-day year of twelve 30-day months.

Any interest payable on any interest payment date other than maturity and not so punctually paid or duly provided for will cease to be payable to the person in whose name the bond is registered at the close of business on the applicable regular record date and will instead be payable to the person in whose name the bond (or one or more predecessor bonds) is registered at the close of business on a special record date for the payment of such interest to be fixed by us, notice of which will be given to the registered holder of the bond (or one or more predecessor bonds) not less than 10 days prior to such special record date. (See Section 307)

Payment of Bonds; Transfers; Exchanges

Interest, if any, on bonds payable on each interest payment date will be paid to the person in whose name such bond is registered (the registered holder of any indenture bond being hereinafter called a "holder") as of the close of business on the regular record date relating to such interest payment date; provided, however, that interest payable at maturity will be paid to the person to whom principal is paid. However, if there has been a default in the payment of interest on any bond, such defaulted interest may be payable to the holder of such bond as of the close of business on a date selected by the trustee which is not more than 15 days or less than 10 days prior to the date proposed by us for payment of such defaulted interest and not less than 10 days after the receipt by the trustee of the notice of the proposed payment or in any other lawful manner not inconsistent with the requirements of any securities exchange on which such bond may be listed, if the trustee deems such manner of payment practicable. (See Section 307)

The principal of and premium, if any, and interest on the bonds at maturity will be payable upon presentation of the bonds at the corporate trust office of JPMorgan Chase Bank in Houston, Texas as paying agent for us. We may change the place of payment on the bonds, may appoint one or more additional paying agents (including us) and may remove any paying agent, all at our discretion. (See Section 602)

The transfer of bonds may be registered, and bonds may be exchanged for other bonds of the same series, of authorized denominations and of like tenor and aggregate principal amount, at the corporate trust office of JPMorgan Chase Bank in Houston, Texas, as bond registrar for the bonds. We may change the place for registration of transfer and exchange of the bonds, and may designate one or more additional places for such registration and exchange, all at our discretion. (See Sections 602 and 305) No service charge will be made for any registration of transfer or exchange of the bonds; however, we may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any registration of transfer or exchange of bonds. We will not be required to execute or to provide for the registration of transfer of or the exchange of:

- any bond during a period of 15 days prior to giving any notice of redemption; or
- any bond selected for redemption, in whole or in part, except the unredeemed portion of any bond being redeemed in part. (See Section 305)

All moneys paid by us to a paying agent or the trustee (or held by us in trust) for the payment of the principal of or any premium or interest on a bond which remain unclaimed at the end of two years after such principal, premium or interest has become due and payable will be repaid to us at our request, and the holder of such bond thereafter may, as an unsecured general creditor, look only to us for payment thereof, and all liability of the paying agent, the trustee and us (as trustee) with respect thereto shall thereupon cease. (See Section 603)

Optional Redemption

The bonds may be redeemed in whole at any time or in part from time to time, at our option, at a redemption price equal to the greater of:

- 100% of the principal amount of the bonds then outstanding to be redeemed; or

- the sum of the present values of the remaining scheduled payments of principal and interest on the bonds to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the date of redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable treasury rate plus 35 basis points;

plus, in each case, accrued and unpaid interest on the principal amount being redeemed to the redemption date.

“treasury rate” means, with respect to any redemption date:

- the yield, under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated “H.15 (519)” or any successor publication which is published weekly by the Board of Governors of the Federal Reserve System and which establishes yields on actively traded U.S. Treasury securities adjusted to constant maturity under the caption “Treasury Constant Maturities,” for the maturity corresponding to the comparable treasury issue (if no maturity is within three months before or after the remaining life (as defined below), yields for the two published maturities most closely corresponding to the comparable treasury issue will be determined and the treasury rate will be interpolated or extrapolated from such yields on a straight line basis, rounding to the nearest month); or
- if such release (or any successor release) is not published during the week preceding the calculation date or does not contain such yields, the rate per annum equal to the semiannual equivalent yield to maturity of the comparable treasury issue, calculated using a price for the comparable treasury issue (expressed as a percentage of its principal amount) equal to the comparable treasury price for such redemption date.

The treasury rate will be calculated on the third business day preceding the date fixed for redemption.

“comparable treasury issue” means the U.S. Treasury security selected by an independent investment banker as having a maturity comparable to the remaining term (“remaining life”) of the bonds to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such notes.

“comparable treasury price” means (1) the average of five reference treasury dealer quotations for such redemption date, after excluding the highest and lowest reference treasury dealer quotations, or (2) if the independent investment banker obtains fewer than four such reference treasury dealer quotations, the average of all such quotations.

“independent investment banker” means Credit Suisse First Boston LLC, Deutsche Bank Securities Inc. or Salomon Smith Barney Inc., as specified by us, or, if these firms are unwilling or unable to select the comparable treasury issue, an independent investment banking institution of national standing appointed by us.

“reference treasury dealer” means (1) Credit Suisse First Boston LLC, Deutsche Bank Securities Inc. and Salomon Smith Barney Inc. and their respective successors, provided, however, that if any of the foregoing shall cease to be a primary U.S. government securities dealer in New York City (a “primary treasury dealer”), we will substitute therefor another primary treasury dealer and (2) any other primary treasury dealer selected by us after consultation with the independent investment banker.

“reference treasury dealer quotations” means, with respect to each reference treasury dealer and any redemption date, the average, as determined by the independent investment banker, of the bid and asked prices for the comparable treasury issue (expressed in each case as a percentage of its principal amount) quoted in writing to the independent investment banker at 5:00 p.m., New York City time, on the third business day preceding such redemption date.

The trustee will mail a notice of redemption to each holder of bonds to be redeemed by first-class mail at least 30 and not more than 60 days prior to the date fixed for redemption. Unless we default on payment of the redemption price, interest will cease to accrue on the bonds or portions thereof called for redemption. If fewer than all of the bonds are to be redeemed, the trustee will select, not more than 60 days prior to the redemption date, the particular bonds or portions thereof for redemption from the outstanding bonds not previously called by such method as the trustee deems fair and appropriate.

THE INDENTURE

Security

Except as otherwise contemplated below under this heading and subject to the exceptions specifically discussed under “—Release of Property” and “—Defeasance,” all outstanding indenture bonds, will be secured, equally and ratably, by the lien of the indenture on substantially all properties owned by us (and not excepted or released from the lien thereof), and improvements, extensions and additions to, and renewals and replacements of, such properties (the “mortgaged property”). The lien of the indenture will be junior, subject and subordinate to the lien of our existing first mortgage indenture.

The term “first mortgage indenture” means the Mortgage and Deed of Trust, dated as of November 1, 1944, from our predecessor in interest, Houston Lighting & Power Company, to JPMorgan Chase Bank (successor to South Texas Commercial National Bank of Houston), as trustee, as heretofore and hereafter amended and supplemented and “first mortgage bonds” means the first mortgage bonds issued thereunder.

The indenture provides that, after the issuance of the initial series of bonds under the indenture and until the first mortgage collateralization date (as defined at the end of this section), we will not issue any additional first mortgage bonds under the first mortgage indenture, except:

- first mortgage bonds in place of, and in substitution for, or to refund, other first mortgage bonds, if (A) the aggregate principal amount of such new first mortgage bonds shall not exceed the aggregate principal amount of such other first mortgage bonds, and (B) the final stated maturity date of such new first mortgage bonds shall be a date not later than the final stated maturity date of such other first mortgage bonds;
- as necessary to replace any mutilated, lost or destroyed first mortgage bonds or to effect exchanges and transfers of first mortgage bonds; and
- if at any time first mortgage bonds are issued pursuant to the first bullet point above, additional first mortgage bonds in an aggregate principal amount of up to \$118 million for the purpose of satisfying the requirement under the indentures pursuant to which certain pollution control bonds were issued by various governmental authorities (which indentures provide that, if we issue first mortgage bonds in certain circumstances, we also are required to issue first mortgage bonds to secure such pollution control bonds on an equal and ratable basis). (See Section 611)

At any time, in our discretion, we may issue and deliver to the trustee as security under the indenture first mortgage bonds in an aggregate principal amount equal to the aggregate principal amount of indenture bonds then outstanding; provided that such first mortgage bonds (the “first mortgage collateral bonds”) shall:

- have terms of payment equivalent to those of such indenture bonds;
- provide that payments by us in respect of principal, premium, if any, or interest due under the indenture bonds will offset our equivalent payment obligations under the first mortgage collateral bonds; and

- provide for the mandatory redemption of the first mortgage collateral bonds upon acceleration of the maturity of such indenture bonds. (See Section 701)

The date on which such first mortgage collateral bonds are delivered to the trustee is referred to herein as the “first mortgage collateralization date.”

Lien of the Indenture

General. The indenture constitutes a lien on substantially all our real property and tangible personal property, other than property excepted from such lien and such property as may be released from such lien in accordance with the terms of the indenture, subject to no liens prior to the lien of the indenture other than the lien of the first mortgage indenture (so long as the same remains in effect) and other liens permitted to exist.

Permitted liens and certain other liens permitted to exist. The indenture provides that after-acquired property (other than excepted property) will be subject to the lien of the indenture; provided, however, that in the case of our consolidation or merger into another entity or transfer of the mortgaged property as or substantially as an entirety, the indenture will not be required to be a lien upon any of the properties then owned or thereafter acquired by the successor entity except properties acquired from us in or as a result of such transaction, and improvements, extensions and additions to such properties and renewals, replacements and substitutions of or for any part or parts thereof and that in the case of a consolidation or merger with respect to which we are the surviving entity, the indenture will not be required to be a lien on any properties acquired by us in or as a result of such transaction or any improvements, extensions or additions to such properties or any renewals, replacements or substitutions of or for any part or parts thereof. (See Article Thirteen) See “—Consolidation, Merger, Etc.” below. In addition, after-acquired property may be subject to liens existing or placed thereon at the time of acquisition thereof, including, but not limited to, purchase money liens.

Without the consent of the holders, we and the trustee may enter into supplemental indentures in order to subject to the lien of the indenture additional property (including property which would otherwise be excepted from such lien). (See Section 1401) Such property would thereupon constitute property additions (so long as it would otherwise qualify as property additions as described below) and be available as a basis for the issuance of indenture bonds. See “—Issuance of Indenture Bonds.”

Excepted Property. There are excepted from the lien of the indenture, among other things:

- cash, deposit accounts, shares of stock, interests in general or limited partnerships, securities not deposited with or held by the trustee;
- contracts, leases and other agreements of all kinds;
- contract rights, bills, notes and other instruments and chattel paper;
- revenues, income and earnings, accounts and accounts receivable and unbilled revenues, rents, tolls, issues, product and profits, claims, demands and judgments;
- governmental and other licenses, permits, franchises, consents and allowances (except to the extent that any of the same constitute rights or interests relating to the occupancy or use of real property);
- certain intellectual property rights, domain names and other general intangibles;
- vehicles, movable equipment and aircraft and supplies used in connection with the foregoing;
- all goods, stock in trade, wares, merchandise and inventory held for sale or lease in the ordinary course of business;

- materials, supplies, inventory and other personal property consumable in the operation of the mortgaged property; fuel; portable tools and equipment; furniture and furnishings;
- computers and data processing, telecommunications and certain other facilities and equipment used primarily for administrative or clerical purposes or not otherwise necessary for the operation or maintenance of facilities and equipment for the generation, transmission and distribution of electric energy and our other buildings and improvements;
- coal, ore, gas, oil and other minerals and timber;
- electric energy, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us;
- real property, gas wells, pipelines, and other facilities used or to be used for the production, gathering, transmission, storage or distribution of natural gas, crude oil or other hydrocarbons or minerals;
- leasehold interests held by us as lessee;
- facilities and equipment for the storage, transmission and distribution of water; and
- other property excepted from or released from the lien of the first mortgage indenture prior to the date of the indenture. (See “Excepted Property” under “Granting Clauses” in the indenture and “Granting Clauses” in the first mortgage indenture.)

Permitted liens. The lien of the indenture is subject to permitted liens and certain other liens permitted to exist. Under the indenture, permitted liens include the following, among other, liens:

- liens for taxes which are not delinquent or are being contested in good faith or which secure charges that do not exceed \$5,000,000;
- mechanics’, workmen’s and similar liens and certain other liens arising in the ordinary course of business;
- liens in respect of judgments:
 - in an amount not exceeding the greater of \$10 million and 3% of the sum of the then outstanding aggregate principal amount of indenture bonds and first mortgage bonds other than first mortgage collateral bonds then outstanding; or
 - with respect to which we shall in good faith be prosecuting an appeal or shall have the right to do so;
- easements, leases or other rights of others in, and defects in title to, the mortgaged property which do not in the aggregate materially impair the use by us of the mortgaged property considered as a whole;
- defects, irregularities and limitations in title to real property subject to rights-of-way in our favor or used primarily for right-of-way purposes;
- liens securing indebtedness and other obligations of others upon real property existing at the date of the indenture or at the time of our acquisition of such property;
- leases existing at the date of the indenture and subsequent leases for not more than 15 years or which do not materially impair our use of the property subject thereto;

- liens of lessors or licensors for amounts due which are not delinquent or are being contested in good faith;
- controls, restrictions or obligations imposed by governmental authorities upon the mortgaged property or the operation thereof;
- rights of governmental authorities to purchase or designate a purchaser of the mortgaged property;
- liens required by law or governmental regulation as a condition to the transaction of any business or the exercise of any privilege or license, or to enable us to maintain self-insurance or to participate in any funds established to cover insurance risks or in connection with workmen's compensation, unemployment insurance, social security or any pension or welfare benefit plan or program;
- liens to secure the performance of duties or public or statutory, bid or performance obligations or surety, stay or appeal bonds;
- rights of others to take minerals, timber, electric energy, gas, water, steam or other products produced by us or by others on our property;
- rights and interests of persons other than us arising out of agreements to which we are a party relating to the common ownership or joint use of property, and liens on the interests of such persons in such property;
- restrictions on assignment and/or qualification requirements on the assignee;
- liens which have been bonded for the full amount in dispute or for the payment of which other security arrangements have been made;
- easements, ground leases or rights-of-way on or across our property for the purpose of roads, pipelines, transmission or distribution lines, communication lines, railways and other similar purposes, provided that the same do not materially impair the use by us of such property or rights-of-way;
- liens on our air or water pollution control, sewage or solid waste disposal or other similar facilities in connection with the issuance of pollution control revenue bonds, in connection with financing the cost of, or construction, acquisition, improvement, repair or maintenance of, such facilities;
- the trustee's lien specified below;
- prepaid liens; and
- the lien of the first mortgage indenture. (See Granting Clauses and Section 101)

"Prepaid lien" means generally any lien securing indebtedness for the payment or redemption of which there shall have been irrevocably deposited in trust with the trustee or other holder of such lien moneys and/or investment securities which (together with the interest reasonably expected to be earned from the investment and reinvestment in investment securities of the moneys and/or the principal of and interest on the investment securities so deposited) shall be sufficient for such purpose; provided, however, that the first mortgage indenture shall not be deemed to be a prepaid lien unless it shall have been satisfied and discharged and all first mortgage bonds issued thereunder shall be deemed to have been paid, all in accordance with the provisions thereof. (See Section 101)

Trustee's Lien. The indenture provides that the trustee will have a lien, prior to the lien on behalf of the holders of indenture bonds, upon the mortgaged property for the payment of its reasonable compensation and expenses and for indemnity against certain liabilities. (See Section 1107)

Issuance of Indenture Bonds

The aggregate principal amount of indenture bonds that may be authenticated and delivered under the indenture is unlimited. (See Section 301). Indenture bonds of any series may be issued from time to time, provided that the first mortgage collateralization date has not occurred, on the basis of property additions, retired bonds (as such terms are defined below) and cash deposited with the trustee, and in an aggregate principal amount not exceeding:

- 70% of the cost (as defined below) or fair value (as defined below) (whichever is less) of property additions (as described below) that do not constitute funded property (as defined below) after certain deductions and additions, primarily including adjustments to offset property retirements;
- the aggregate principal amount of retired bonds; and
- an amount of cash deposited with the trustee. (See Article Four)

In addition, any issuance of indenture bonds after March 31, 2003, other than any issuance on the basis of retired bonds having an applicable interest rate not less than the interest rate applicable to the indenture bonds to be issued, requires that we provide a certificate demonstrating that the adjusted net earnings (as defined below) for the specified 12 month period are not less than 200% of the annual interest requirements (as defined below) for the specified one year period.

“Adjusted net earnings” means the amount for a period of 12 consecutive calendar months within the 18 calendar months immediately preceding the first day of the month in which we intend to issue additional indenture bonds (or, in the case of any such certificate to be delivered on or prior to June 30, 2003, for a period of 12 consecutive calendar months within the 15 calendar months immediately preceding the first day of such month):

- our operating revenues for such period; minus
- our operating expenses, excluding:
 - expenses for taxes on income or profits;
 - provisions for reserves for depreciation, amortization, depletion or retirement of property;
 - interest expense, including the amortization of debt discount, premium, expense or loss on reacquired debt, for any replacement, sinking fund or other device for the retirement or amortization of any indebtedness;
 - non-recurring charge or expenses; and
 - provisions for any refund of our revenues previously collected or accrued; plus
- our other income, net of related expenses (excluding expenses or provisions for any non-recurring charges).

“Annual interest requirements” means the interest requirements for one year, at the respective stated interest rates, if any, borne before maturity, upon:

- all outstanding indenture bonds, except any for the payment or redemption of which indenture bonds applied for are to be issued;
- all indenture bonds then applied for in pending applications for the original issuance of indenture bonds, including the application in connection with which such certificate is made;

- all outstanding first mortgage bonds, except any for the payment or redemption of which the indenture bonds applied for are to be issued; and
- the principal amount of all other indebtedness, except:
 - first mortgage collateral bonds;
 - our indebtedness, the repayment of which supports or is supported by other indebtedness included in annual interest requirements pursuant to one of the other clauses of this definition;
 - indebtedness for the payment of which the indenture bonds applied for are to be issued; and
 - indebtedness secured by a prepaid lien prior to the lien of the indenture upon property subject to such lien, outstanding on the date of such computation and secured by a lien on a parity with or prior to the lien of the indenture upon property subject to the lien of the indenture, if such indebtedness has been issued, assumed or guaranteed by us or if we customarily pay the interest upon the principal thereof or collections from our customers are applied to, or pledged as security for the payment of such interest;

provided, however, that if any such indebtedness bears interest at a variable rate, then the interest requirement on such indebtedness shall be determined by reference to the rate in effect on the day immediately preceding the date of such computation; and provided, further, that any amounts collected by others to be applied to debt service on our indebtedness, and not otherwise treated on our books as revenue, shall be added to our operating revenues when determining adjusted net earnings.

“Cost” with respect to property additions generally means the sum of:

- any cash paid in the acquisition of such property;
- an amount equivalent to the fair market value in cash of any securities or other property paid in the acquisition of such property;
- the principal amount of any obligations secured by prior lien (other than the lien of the first mortgage indenture) upon such property additions outstanding at the time of the acquisition thereof;
- the principal amount of any other obligations incurred or assumed in connection with the payment for such property additions or for the acquisition thereof; and
- any other amounts which, in accordance with generally accepted accounting principles, are properly charged or chargeable to our plant or other property accounts with respect to such property additions as part of the cost of construction or acquisition thereof, including, but not limited to any allowance for funds used during construction or any similar or analogous amount;
- provided, however, that:
 - with respect to property additions owned by our successor immediately prior to the time it shall have become such successor in or as a result of an acquisition, consolidation or merger, cost shall mean the amount or amounts at which such property additions are recorded in the plant or other property accounts of such successor, or the predecessor from which such property additions are acquired, as the case may be, immediately prior to such consolidation or merger;
 - with respect to property additions which shall have been acquired (otherwise than by construction) by us without any consideration consisting of cash, securities or other property or the incurring or

assumption of indebtedness or other obligation, no determination of cost shall be required and, wherever provision is made for cost or fair value, cost with respect to such property additions shall mean an amount equal to the fair value to us thereof or, if greater, the aggregate amount reflected in our books of account with respect thereto upon the acquisition thereof; and

- in no event shall the cost of property additions be required to reflect any depreciation or amortization in respect of such property additions, or any adjustment to the amount or amounts at which such property additions are recorded in plant or other property accounts due to the non-recoverability of investment or otherwise.

If any property additions include property which has been used or operated by third parties in a business similar to that in which it has been or is to be used or operated by us, the cost thereof need not be reduced by any amount in respect of any goodwill, going concern value rights and/or intangible property simultaneously acquired and in such case the term property additions as defined herein may include such goodwill, going concern value rights and intangible property.

“Fair value,” with respect to property, generally means the fair value of such property as may reasonably be determined by reference to:

- the amount which would be likely to be obtained in an arm’s-length transaction with respect to such property between an informed and willing buyer and an informed and willing seller, under no compulsion, respectively, to buy or sell;
- the amount of investment with respect to such property which, together with a reasonable return thereon, would be likely to be recovered through ordinary business operations or otherwise;
- the cost, accumulated depreciation and replacement cost with respect to such property; and/or
- any other relevant factors; provided, however, that:
 - the fair value of property shall be determined without deduction for any liens on such property prior to the lien of the indenture; and
 - the fair value of property additions shall not reflect any reduction relating to the fact that such property additions may be of less value to a person which is not the owner or operator of the mortgaged property or any portion thereof than to the owner or operator. Fair value may be determined, in the discretion of the expert certifying the same, without physical inspection, by the use of accounting and/or engineering records and/or other data maintained by us or otherwise available to such expert.

“Funded property” generally includes property additions which have been designated funded property in an expert’s certificate, which have been made the basis of the authentication and delivery of indenture bonds, which have been made the basis for the release of mortgaged property, which have been made the basis for the withdrawal of cash, which have been substituted for retired funded property or which have been used for other specified purposes. (See Section 102)

“Property additions” generally include any property which is owned by us and is subject to the lien of the indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the cost of acquisition or construction of which is properly chargeable to one of our operating expense accounts. (See Section 103)

“Retired bonds” means, generally:

- indenture bonds which are no longer outstanding under the indenture, which have not been retired by the application of funded cash and which have not been used as the basis for the authentication and delivery of indenture bonds, the release of property or the withdrawal of cash; and
- certain first mortgage bonds issued under the first mortgage indenture which could be used as a basis for the authentication and delivery of additional first mortgage bonds under the first mortgage indenture and have been retired after the initial issuance of indenture bonds under the indenture;

provided, however, that no first mortgage bond may be used as the basis for the authentication and delivery of both additional indenture bonds and additional first mortgage bonds. (See Section 101).

Release of Property

Unless an event of default (as defined below) has occurred and is continuing, we may obtain the release from the lien of the indenture of any funded property upon delivery to the trustee of certain certificates and an amount in cash equal to the amount, if any, by which 70% of the cost of the property to be released (or, if less, the fair value of such property at the time it became funded property) exceeds the aggregate of:

- an amount equal to 70% of the aggregate principal amount of obligations secured by purchase money liens delivered to the trustee, subject to certain limitations described below;
- an amount equal to 70% of the cost or fair value (whichever is less) of certified property additions not constituting funded property after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such property additions were acquired or made within the 90-day period preceding the release);
- the aggregate principal amount of indenture bonds we would be entitled to issue on the basis of retired bonds (with such entitlement being waived by operation of such release);
- any amount of cash and/or an amount equal to 70% of the aggregate principal amount of obligations secured by purchase money liens upon the property released delivered to the trustee or other holder of a lien prior to the lien of the indenture, subject to certain limitations described below;
- on or after the first mortgage collateralization date, the aggregate principal amount of first mortgage bonds delivered to the trustee to be held as first mortgage collateral bonds;
- the aggregate principal amount of outstanding indenture bonds delivered to the trustee (with such indenture bonds to be canceled by the trustee); and
- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released. (See Section 803)

As used in the indenture, the term “purchase money lien” means, generally, a lien on the property being acquired, disposed of by us or being released from the lien of the indenture, which is taken or retained by the transferor of such property to secure all or part of the purchase price thereof or granted to one or more other persons (other than the transferor) who by making advances or incurring an obligation, give value to enable the grantor of the lien to acquire rights in such property, or granted to another person in connection with the release of property from the lien of the indenture on the basis of a deposit with the trustee or other holder of a lien prior to the lien of the indenture of obligations secured by such lien on such property, or held by a trustee or agent for the benefit of any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property. (See Section 101) Generally, the principal amount of obligations secured by purchase money liens used as the basis for the release of property may

not exceed 75% of the fair value of such property unless no additional obligations are outstanding, or are permitted to be issued, under such purchase money lien. (See Section 803)

Property which is not funded property may generally be released from the lien of the indenture without depositing any cash or property with the trustee as long as:

- the aggregate amount of cost or fair value (whichever is less) of all property additions which do not constitute funded property (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero; or
- the cost or fair value (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value (whichever is less) of property additions acquired or made within the 90-day period preceding the release. (See Section 804)

The indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the trustee. (See Sections 802, 805, 807 and 808)

If we retain any interest in any property released from the lien of the indenture, the indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof. (See Section 809)

Withdrawal of Cash

Unless an event of default has occurred and is continuing and subject to certain limitations, cash held by the trustee may, generally:

- be withdrawn by us:
 - to the extent of an amount equal to 70% of the cost or fair value to us (whichever is less) of property additions not constituting funded property, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such property additions were acquired or made within the 90-day period preceding the withdrawal); or
 - in an amount equal to the aggregate principal amount of indenture bonds that we would be entitled to issue on the basis of retired bonds (with the entitlement to such issuance being waived by operation of such withdrawal); or
 - on or after the first mortgage collateralization date, in an amount equal to the aggregate principal amount of first mortgage bonds delivered to the trustee to be held as first mortgage collateral bonds; or
 - in an amount equal to the aggregate principal amount of outstanding indenture bonds delivered to the trustee; or
- upon our request, be applied to the purchase of indenture bonds or the payment (or provision therefor) at stated maturity of any indenture bonds or the redemption (or provision therefor) of any indenture bonds which are redeemable. (See Section 806)

Consolidation, Merger, Etc.

We may not consolidate with or merge into any other entity or convey, transfer or lease, subject to the lien of this indenture, the mortgaged property as or substantially as an entirety to any entity unless:

- the entity formed by such consolidation or into which we are merged or the entity which acquires by conveyance or transfer, or which leases, the mortgaged property as or substantially as an entirety is an entity organized and existing under the laws of the United States, or any State or Territory thereof or the District of Columbia; and
- such entity executes and delivers to the trustee a supplemental indenture that:
 - in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the indenture bonds then outstanding, contains an express assumption by such entity of the due and punctual payment of the principal of and premium, if any, and interest, if any, on the indenture bonds and the performance of all of our covenants and conditions under the indenture; and
 - in the case of a consolidation, merger, conveyance or other transfer, contains a grant, conveyance, transfer and mortgage by such entity:
 - confirming the lien of the indenture on the mortgaged property; and
 - subjecting to such lien all property thereafter acquired by such entity that shall constitute an improvement, extension or addition to the mortgaged property or renewal, replacement or substitution of or for any part thereof and, at the election of such entity, subjecting to the lien of the indenture such other property then owned or thereafter acquired by such entity as such entity shall specify; and
- in the case of a lease, such lease is made expressly subject to termination by us or by the trustee at any time during the continuance of an event of default; and
- immediately after giving effect to such transaction, no event of default and no event which, with notice or lapse of time or both, would become an event of default shall have occurred and be continuing. (See Section 1301)

In the case of the conveyance or other transfer of the mortgaged property as or substantially as an entirety to any other entity, upon the satisfaction of all the conditions described above, we would be released and discharged from all obligations under the indenture and on the indenture bonds then outstanding unless we elect to waive such release and discharge. (See Section 1304). For purposes of this section, "entity" means a corporation, limited liability company, company, association, joint-stock company, partnership, limited liability partnership, joint venture, trust, unincorporated organization or governmental authority.

Modification of Indenture

Modifications without Consent. Without the consent of any holders, we and the trustee may enter into one or more supplemental indentures for any of the following purposes, among others:

- to evidence the succession of another entity to us and the assumption by any such successor of our covenants and agreements in the indenture and in the indenture bonds; or
- to add one or more covenants or other provisions for the benefit of all holders or for the benefit of the holders of, or to remain in effect only so long as there shall be outstanding, indenture bonds of one or

more specified series (for the purposes of this subsection, “series” includes tranches thereof), or to surrender any right or power conferred upon us by the indenture; or

- to correct or amplify the description of any property at any time subject to the lien of the indenture; or better to assure, convey and confirm to the trustee any property subject or required to be subjected to the lien of the indenture; or to subject to the lien of the indenture additional property (including property of others); to specify any additional permitted liens with respect to such additional property and to modify the provisions in the indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property; or
- to establish the form or terms of the indenture bonds of any series as permitted by the indenture; or
- to provide for the authentication and delivery of bearer bonds and coupons appertaining thereto representing interest, if any, thereon and for the procedures for the registration, exchange and replacement thereof and for the giving of notice to, and the solicitation of the vote or consent of, the holders thereof, and for any and all other matters incidental thereto; or
- to evidence and provide for the acceptance of appointment by a successor trustee or by a co-trustee; or
- to provide for the procedures required to permit the utilization of a non-certificated system of registration for all, or any series of, the indenture bonds; or
- to change any place or places where:
 - the principal of and premium, if any, and interest, if any, on all or any series of indenture bonds will be payable;
 - all or any series of indenture bonds may be surrendered for registration of transfer;
 - all or any series of indenture bonds may be surrendered for exchange; and
 - notices and demands to or upon us in respect of all or any series of indenture bonds and the indenture may be served; or
- to comply with the rules of any securities exchange on which any series of indenture bonds may be listed; or
- to modify this indenture to comply with the Trust Indenture Act of 1939, as amended (the “Trust Indenture Act”); or
- to cure any ambiguity, to correct or supplement any provision therein which may be defective or inconsistent with any other provision therein, or to make any other additions to, deletions from or other changes to the provisions thereof; provided that such additions, deletions and/or other changes do not adversely affect the interests of the holders of indenture bonds of any series in any material respect. (See Section 1401)

Without limiting the generality of the foregoing, if the Trust Indenture Act is amended after the date of the indenture in such a way as to require changes to the indenture or the incorporation therein of additional provisions or so as to permit changes to, or the elimination of, provisions which, at the date of the indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the indenture, the indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and we and the trustee may, without the consent of any holders, enter into one or more supplemental indentures to evidence or effect such amendment. (See Section 1401)

Modifications Requiring Consent. Except as provided above, the consent of the holders of not less than a majority in aggregate principal amount of the indenture bonds of all series then outstanding, considered as one class, is required for the purpose of adding any provisions to, or changing in any manner, or eliminating any of the provisions of, the indenture pursuant to one or more supplemental indentures; provided, however, that if less than all of the series of indenture bonds outstanding are directly affected by a proposed supplemental indenture, then the consent only of the holders of a majority in aggregate principal amount of outstanding indenture bonds of all series so directly affected, considered as one class, will be required; and provided, further, that if the indenture bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of one or more, but less than all such tranches, then the consent only of the holders of a majority in aggregate principal amount of the outstanding indenture bonds of all such tranches so directly affected, considered as one class, will be required; and provided, further, that no such amendment or modification may:

- change the stated maturity of the principal of, or any installment of principal of or interest on, any indenture bond, or reduce the principal amount thereof or the rate of interest thereon (or the amount of any installment of interest thereon) or change the method of calculating such rate or reduce any premium payable upon the redemption thereof, or reduce the amount of the principal of any discount bond or other indenture bond that would be due and payable upon a declaration of acceleration of maturity or change the coin or currency in which any indenture bond or any premium or the interest thereon is payable, or impair the right to institute suit for the enforcement of any such payment on or after the stated maturity of any indenture bond (or, in the case of redemption, on or after the redemption date) without, in any such case, the consent of the holder of such indenture bond;
- permit the creation of any lien (not otherwise permitted by the indenture) ranking prior to the lien of the indenture with respect to all or substantially all of the mortgaged property or terminate the lien of the indenture on all or substantially all of the mortgaged property or deprive the holders of the benefit of the lien of the indenture, without, in any such case, the consent of the holders of all indenture bonds then outstanding;
- reduce the percentage in principal amount of the outstanding indenture bonds of any series, or tranche thereof, the consent of the holders of which is required for any such supplemental indenture, or the consent of the holders of which is required for any waiver of compliance with any provision of the indenture or of any default thereunder and its consequences, or reduce the requirements for quorum or voting, without, in any such case, the consent of the holder of each outstanding indenture bond of such series; or
- modify any of the provisions (with certain exceptions) of the indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to the indenture bonds without the consent of the holder of each outstanding indenture bond affected thereby.

A supplemental indenture that changes or eliminates any covenant or other provision of the indenture that has expressly been included solely for the benefit of the holders of, or that is to remain in effect only so long as there shall be outstanding, indenture bonds of one or more specified series or modifies the rights of the holders of indenture bonds of such series with respect to such covenant or other provision, will be deemed not to affect the rights under the indenture of the holders of the indenture bonds of any other series. (See Section 1402)

Waiver

The holders of at least a majority in aggregate principal amount of all indenture bonds may waive our obligations to comply with certain covenants, including the covenants to maintain our corporate or other legal existence and properties, pay taxes and discharge liens and maintain certain insurance and our covenant with respect to merger, consolidation or the transfer or lease of the mortgaged property as or substantially as an entirety, described above, provided that such waiver occurs before the time such compliance is required. The holders of at

least a majority of the aggregate principal amount of outstanding indenture bonds of all affected series or tranches, considered as one class, may waive, before the time for such compliance, compliance with any covenant specified with respect to indenture bonds of such series or tranches thereof. (See Section 609) The holders of at least a majority in aggregate principal amount of all indenture bonds outstanding may waive past defaults, not including defaults in the payment of principal, premium or interest or defaults with respect to provisions that cannot be modified without the consent of each holder affected thereby, under the indenture. (See Section 1017)

Events of Default

Each of the following events constitutes an event of default under the indenture:

- failure to pay interest on any indenture bond within 30 days after the same becomes due and payable;
- failure to pay principal of or premium, if any, on any indenture bond when it becomes due and payable;
- failure to perform or breach of any of our covenants or warranties in the indenture (other than a covenant or warranty a default in the performance of which or breach of which is dealt with elsewhere under this paragraph) for a period of 90 days after there has been given to us by the trustee, or to us and the trustee by the holders of at least 33% in principal amount of outstanding indenture bonds, a written notice specifying such default or breach and requiring it to be remedied and stating that such notice is a “notice of default,” unless the trustee, or the trustee and the holders of a principal amount of indenture bonds not less than the principal amount of indenture bonds the holders of which gave such notice, as the case may be, agree in writing to an extension of such period prior to its expiration; provided, however, that the trustee, or the trustee and such holders, as the case may be, will be deemed to have agreed to an extension of such period if corrective action has been initiated by us within such period and is being diligently pursued;
- certain events relating to reorganization, bankruptcy and insolvency of us or appointment of a receiver or trustee for our property (See Section 1001); and
- the occurrence of any default or any other event under the first mortgage indenture, and the expiration of the applicable grace period, if any, specified in such first mortgage indenture, if the effect of such default or event is to accelerate, or to permit the acceleration of, the maturity of any amount due under the first mortgage indenture.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then the trustee or the holders of not less than 33% in principal amount of indenture bonds then outstanding may declare the principal amount (or if the indenture bonds are discount bonds, such portion of the principal amount as may be provided for such discount bonds pursuant to the terms of the indenture) of all of the indenture bonds then outstanding, together with premium, if any, and accrued interest, if any, thereon to be immediately due and payable. At any time after such declaration of acceleration of the indenture bonds then outstanding, but before the sale of any of the mortgaged property and before a judgment or decree for payment of money shall have been obtained by the trustee as provided in the indenture, the event or events of default giving rise to such declaration of acceleration will, without further act, be deemed to have been waived, and such declaration and its consequences will, without further act, be deemed to have been rescinded and annulled, if:

- we have paid or deposited with the trustee a sum sufficient to pay:
 - all overdue interest, if any, on all indenture bonds then outstanding;

- the principal of and premium, if any, on any indenture bonds then outstanding which have become due otherwise than by such declaration of acceleration and interest thereon at the rate prescribed therefor in such indenture bonds; and
- all amounts due to the trustee as compensation and reimbursement as provided in the indenture; and
- any other event or events of default, other than the non-payment of the principal of indenture bonds that shall have become due solely by such declaration of acceleration, shall have been cured or waived as provided in the indenture. (See Section 1002)

Possession of Mortgaged Property

Under certain circumstances and to the extent permitted by law, if an event of default occurs and is continuing, the trustee has the power to take possession of, and to hold, operate and manage, the mortgaged property, or with or without entry, sell the mortgaged property. If the mortgaged property is sold, whether by the trustee or pursuant to judicial proceedings, the principal of the outstanding indenture bonds, if not previously due, will become immediately due and payable, together with premium, if any, and any accrued interest. (See Sections 1003, 1004 and 1005)

Right to Direct Proceedings

If an event of default occurs and is continuing, the holders of a majority in principal amount of the indenture bonds then outstanding will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the trustee or exercising any trust or power conferred on the trustee, provided that such direction does not conflict with any rule of law or with the indenture, and could not involve the trustee in personal liability in circumstances where indemnity would not, in the trustee's sole discretion, be adequate and the trustee may take any other action deemed proper by the trustee that is not inconsistent with such direction. (See Section 1016)

Limitation on Right to Institute Proceedings

No holder of any indenture bond will have any right to institute any proceeding, judicial or otherwise, with respect to the indenture or for the appointment of a receiver or for any other remedy thereunder unless

- such holder has previously given to the trustee written notice of a continuing event of default;
- the holders of not less than a majority in aggregate principal amount of the indenture bonds then outstanding have made written request to the trustee to institute proceedings in respect of such event of default and have offered the trustee reasonable indemnity against costs and liabilities to be incurred in complying with such request; and
- for sixty days after receipt of such notice, the trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the trustee during such sixty-day period by the holders of a majority in aggregate principal amount of indenture bonds then outstanding.

Furthermore, no holder will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders. (See Section 1011)

No Impairment of Right to Receive Payment

Notwithstanding that the right of a holder to institute a proceeding with respect to the indenture is subject to certain conditions precedent, each holder of an indenture bond has the absolute and unconditional right to receive

payment of the principal of and premium, if any, and interest, if any, on such indenture bond when due and to institute suit for the enforcement of any such payment, and such rights may not be impaired without the consent of such holder. (See Section 1012)

Notice of Default

The trustee is required to give the holders notice of any default under the indenture to the extent required by the Trust Indenture Act, unless such default shall have been cured or waived, except that no such notice to holders of a default of the character described in the third bullet point under “Events of Default” may be given until at least 75 days after the occurrence thereof. (See Section 1102) The Trust Indenture Act currently permits the trustee to withhold notices of default (except for certain payment defaults) if the trustee in good faith determines the withholding of such notice to be in the interests of the holders.

Indemnification of Trustee

As a condition precedent to certain actions by the trustee in the enforcement of the lien of the indenture and institution of action on the indenture bonds, the trustee may require adequate indemnity against costs, expenses and liabilities to be incurred in connection therewith. (See Sections 1011 and 1101)

Remedies Limited by State Law

The laws of any jurisdiction where the mortgaged property is located may limit or deny the ability of the trustee or bondholders to enforce certain rights and remedies provided in the indenture in accordance with their terms.

Defeasance

Any indenture bonds, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the indenture, and, at our election, the entirety of our indebtedness in respect thereof will be deemed to have been satisfied and discharged, if there has been irrevocably deposited with the trustee or any paying agent (other than us), in trust:

- money (including funded cash not otherwise applied pursuant to the indenture) in an amount which will be sufficient; or
- in the case of a deposit made prior to the date on which principal is due, eligible obligations (as described below), which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the trustee or such paying agent, will be sufficient; or
- a combination of options in the preceding bullet points which will be sufficient, to pay when due the principal of and premium, if any, and interest, if any, due and to become due on such indenture bonds or portions thereof. (See Section 901) For this purpose, eligible obligations include direct obligations of, or obligations unconditionally guaranteed by, the United States of America, entitled to the benefit of the full faith and credit thereof, and certificates, depositary receipts or other instruments that evidence a direct ownership interest in such obligations or in any specific interest or principal payments due in respect thereof.

Notwithstanding the foregoing, no indenture bond shall be deemed to have been paid as aforesaid unless we shall have delivered to the trustee either:

- an opinion of counsel in the United States reasonably acceptable to the trustee confirming that (i) we have received from, or there has been published by, the Internal Revenue Service a ruling or (ii) since the date of the indenture, there has been a change in the applicable federal income tax law, in either case to the effect that, and based thereon such opinion of counsel shall confirm that, the holders of the outstanding indenture bonds will not recognize income, gain or loss for federal income tax purposes as a result of such defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such defeasance had not occurred; or
- an instrument wherein we, notwithstanding the satisfaction and discharge of our indebtedness in respect of indenture bonds, shall assume the obligation (which shall be absolute and unconditional) to irrevocably deposit with the trustee such additional sums of money, if any, or additional government obligations, if any, or any combination thereof, at such time or times, as shall be necessary, together with the money and/or government obligations theretofore so deposited, to pay when due the principal of and premium, if any, and interest due and to become due on such indenture bonds or portions thereof; provided, however, that such instrument may state that our obligation to make additional deposits as aforesaid shall be subject to the delivery to us by the trustee of a notice asserting the deficiency accompanied by an opinion of an independent public accountant of nationally recognized standing showing the calculation thereof; and
- an opinion of tax counsel in the United States reasonably acceptable to the trustee to the effect that the holders of the outstanding indenture bonds will not recognize income, gain or loss for federal income tax purposes as a result of such defeasance and will be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such defeasance had not occurred.

Duties of the Trustee; Resignation; Removal

The trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to such provisions, the trustee will be under no obligation to exercise any of the powers vested in it by the indenture at the request of any holder of indenture bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The trustee may resign at any time by giving written notice thereof to us or may be removed at any time by the holders of a majority in principal amount of indenture bonds then outstanding delivered to the trustee and us. No resignation or removal of the trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the indenture. So long as no event of default or event which, after notice or lapse of time, or both, would become an event of default has occurred and is continuing, if we have delivered to the trustee a resolution of our board of directors appointing a successor trustee and such successor has accepted such appointment in accordance with the terms of the indenture, the trustee will be deemed to have resigned and the successor will be deemed to have been appointed as trustee in accordance with the indenture. (See Section 1110)

Evidence to be Furnished to the Trustee

Compliance with indenture provisions is evidenced by written statements of our officers or persons selected or paid by us. In certain cases, opinions of counsel and certification of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the indenture requires that we give

the trustee, not less often than annually, a brief statement as to our compliance with the conditions and covenants under the indenture.

**DESCRIPTION OF CENTERPOINT ENERGY RESOURCES CORP.'S SECURITIES
REGISTERED PURSUANT TO SECTION 12
OF THE SECURITIES EXCHANGE ACT OF 1934**

As of December 31, 2025, CenterPoint Energy Resources Corp., a Delaware corporation, had one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) the 6.625% senior notes due 2037 ("Senior Notes" or "notes"). For purposes of this summary, the terms "we," "our," "ours," and "us" refer only to CenterPoint Energy Resources Corp. and not to any of our subsidiaries.

DESCRIPTION OF THE SENIOR NOTES

Our debt securities are issued under an indenture, dated as of February 1, 1998, as supplemented, between us and The Bank of New York Mellon Trust Company, N.A. (successor to JPMorgan Chase Bank, National Association), as trustee (the "Indenture"), as amended and supplemented, in the case of the Senior Notes, by Supplemental Indenture No. 12, dated as of October 23, 2007, each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4(v) is a part. As of December 31, 2025, \$250,000,000 aggregate principal amount of the Notes were outstanding. We have summarized selected provisions of the Indenture and the Senior Notes below. This summary is not complete and is qualified in its entirety by reference to the Indenture and Supplemental Indenture No. 12. We encourage you to read the above referenced Indenture and Supplemental Indenture No. 12 for additional information.

Ranking of the Senior Notes. The Senior Notes:

- are general unsecured obligations,
- rank equally in right of payment with all of our other existing and future unsecured and unsubordinated indebtedness, and
- with respect to the assets and earnings of our subsidiaries, structurally rank below all of the liabilities of our subsidiaries.

Principal, Maturity and Interest. The Senior Notes mature on November 1, 2037. Interest on the Senior Notes accrues at the rate of 6.625% per annum. Interest on the Senior Notes:

- is payable semi-annually in arrears on each May 1 and November 1,
- is payable to the person in whose name the notes are registered at the close of business on the April 15 and October 15 immediately preceding the applicable interest payment date, which we refer to with respect to the notes as "regular record dates,"
- is computed on the basis of a 360-day year comprised of twelve 30-day months, and
- is payable on overdue interest to the extent permitted by law at the same rate as interest is payable on

If any interest payment date, the maturity date or any redemption date falls on a day that is not a business day, the payment will be made on the next business day with the same force and effect as if made on the relevant

interest payment date, maturity date or redemption date. Unless we default on a payment, no interest will accrue for the period from and after the applicable maturity date or redemption date.

Optional Redemption. We may redeem the Senior Notes, in whole or in part, at our option exercisable at any time and from time to time upon not less than 30 and not more than 60 days' notice as provided in the indenture, on any date prior to their maturity at a redemption price equal to:

- 100% of the principal amount of the notes to be redeemed, plus
- accrued and unpaid interest thereon, if any, to, but excluding, the redemption date, plus
- the make-whole premium described below, if any.

The redemption price will never be less than 100% of the principal amount of the Senior Notes redeemed plus accrued and unpaid interest thereon, if any, to, but excluding, the redemption date. The amount of the make-whole premium with respect to any note to be redeemed will be equal to the excess, if any, of:

- (1) the sum of the present values, calculated as of the redemption date, of:
 - each interest payment that, but for such redemption, would have been payable on the note or portion thereof being redeemed on each interest payment date occurring after the redemption date (excluding any accrued and unpaid interest for the period prior to the redemption date), and
 - the principal amount that, but for such redemption, would have been payable at the final maturity of the note or portion thereof being redeemed, over
- (2) the principal amount of the note or portion thereof being redeemed.

The present values of interest and principal payments referred to in clause (1) above will be determined in accordance with generally accepted principles of financial analysis. These present values will be calculated by discounting the amount of each payment of interest or principal from the date that each such payment would have been payable, but for the redemption, to the redemption date at a discount rate equal to the comparable treasury yield (as defined below) plus 30 basis points.

The make-whole premium will be calculated by an independent investment banking institution of national standing appointed by us. If we fail to appoint an independent investment banking institution at least 45 days prior to the redemption date, or if the independent investment banking institution we appoint is unwilling or unable to calculate the make-whole premium, the calculation will be made by Citigroup Global Markets Inc., Morgan Stanley & Co. Incorporated or UBS Securities LLC. If Citigroup Global Markets Inc., Morgan Stanley & Co. Incorporated and UBS Securities LLC are unwilling or unable to make the calculation, we will appoint a different independent investment banking institution of national standing to make the calculation.

For purposes of determining the make-whole premium, "comparable treasury yield" means a rate of interest per annum equal to the weekly average yield to maturity of United States Treasury Securities that have a constant maturity that corresponds to the remaining term to maturity of the notes to be redeemed, calculated to the nearest 1/12th of a year. The comparable treasury yield will be determined as of the third business day immediately preceding the applicable redemption date.

The weekly average yields of United States Treasury Securities will be determined by reference to the most recent statistical release published by the Federal Reserve Bank of New York and designated "H.15(519) Selected Interest Rates" or any successor release. If this statistical release sets forth a weekly average yield for United States Treasury Securities having a constant maturity that is the same as the remaining term of the notes to be redeemed

calculated as set forth above, then the comparable treasury yield will be equal to such weekly average yield. In all other cases, the comparable treasury yield will be calculated by interpolation on a straight-line basis, between the weekly average yields on the United States Treasury Securities that have a constant maturity closest to and greater than the remaining term of the notes to be redeemed and the United States Treasury Securities that have a constant maturity closest to and less than the remaining term of notes (in each case as set forth in the H.15 statistical release or any successor release). Any weekly average yields calculated by interpolation will be rounded to the nearest 1/100th of 1%, with any figure of 1/200th of 1% or above being rounded upward. If weekly average yields for United States Treasury Securities are not available in the H.15 statistical release or otherwise, then the comparable treasury yield will be calculated by interpolation of comparable rates selected by an independent investment banking institution selected in the manner described in the second preceding paragraph.

If we redeem less than all the Senior Notes, the trustee will select the Senior Notes for redemption on a pro rata basis, by lot or by such other method as the trustee in its sole discretion deems fair and appropriate. We will only redeem notes in multiples of \$1,000 in original principal amount. If any note is to be redeemed in part only, the notice of redemption will state the portion of the principal amount to be redeemed. A new note in principal amount equal to the unredeemed portion of the original note will be issued upon the cancellation of the original note.

Sinking Fund. We are not obligated to make mandatory redemption or sinking fund payments with respect to the Senior Notes.

Restrictive Covenants. The Indenture does not limit the amount of indebtedness or other obligations that we may incur and does not contain provisions that would give holders of the notes the right to require us to repurchase their notes in the event of a change in control of us, or in the event we enter into one or more highly leveraged transactions, regardless of whether a rating decline results therefrom, or in the event we dispose of one or more of our business units, nor are any such events deemed to be events of default under the terms of the Indenture.

Limitations on Liens. We will not, and we will not permit any subsidiary (as defined below) to, pledge, mortgage or hypothecate, or permit to exist, except in our favor or in favor of any subsidiary, any lien (as defined below) upon any principal property (as defined below) or any equity interest (as defined below) in any significant subsidiary (as defined below) owning any principal property, at any time owned by us or by a subsidiary, to secure any indebtedness (as defined below), unless effective provision is made whereby outstanding notes will be secured equally and ratably therewith (or prior thereto), and with any other indebtedness similarly entitled to be equally and ratably secured. This restriction will not apply to or prevent the creation or existence of:

- liens on any property held or used by us or a subsidiary in connection with the exploration for, development of or production of, oil, gas, natural gas (including liquefied gas and storage gas), other hydrocarbons, helium, coal, metals, minerals, steam, timber, geothermal or other natural resources or synthetic fuels, such properties to include, but not be limited to, our or a subsidiary's interest in any mineral fee interests, oil, gas or other mineral leases, royalty, overriding royalty or net profits interests, production payments and other similar interests, wellhead production equipment, tanks, field gathering lines, leasehold or field separation and processing facilities, compression facilities and other similar personal property and fixtures,
- liens on oil, gas, natural gas (including liquefied gas and storage gas), other hydrocarbons, helium, coal, metals, minerals, steam, timber, geothermal or other natural resources or synthetic fuels produced or recovered from any property, an interest in which is owned or leased by us or a subsidiary,
- liens (or certain extensions, renewals or refundings thereof) upon any property acquired, constructed or improved before or after the date the notes are first issued, which liens were or are created at the later of the time of acquisition or commercial operation thereof, or within one year thereafter to secure all or a portion of the purchase price thereof or the cost of construction or improvement, or existing thereon at the date of acquisition, provided that every such mortgage, pledge, lien or encumbrance applies only to the property so acquired or constructed and fixed improvements thereon,
- liens upon any property of any entity acquired by any entity that is or becomes a subsidiary after the date the notes are first issued, each of which we refer to as an "acquired entity," provided that every such mortgage, pledge, lien or encumbrance:
 - will either:
 - exist prior to the time the acquired entity becomes a subsidiary, or
 - be created at the time the acquired entity becomes a subsidiary or within one year thereafter to secure payment of the acquisition price thereof, and
 - will only apply to those properties owned by the acquired entity at the time it becomes a subsidiary or thereafter acquired by it from sources other than us or any other subsidiary,
- pledges of current assets, in the ordinary course of business, to secure current liabilities,
- deposits, including among others, good faith deposits in connection with tenders, leases of real estate or bids or contracts, or liens, including among others, liens reserved in leases and mechanics' or materialmen's liens, to secure certain duties or public or statutory obligations,
- liens upon any office, data processing or transportation equipment,
- liens created or assumed in connection with the issuance of debt securities, the interest on which is excludable from gross income of the holder of such security pursuant to the Internal Revenue Code, for the purpose of financing the acquisition or construction of property to be used by us or a subsidiary,
- pledges or assignments of accounts receivable or conditional sales contracts or chattel mortgages and evidence of indebtedness secured thereby, received in connection with the sale of goods or merchandise to
- certain liens for taxes, judgments and attachments.

Notwithstanding the foregoing, we or a subsidiary may issue, assume or guarantee indebtedness secured by a mortgage which would otherwise be subject to the foregoing restrictions in an aggregate amount which, together

with all of our other indebtedness or indebtedness of a subsidiary secured by a mortgage (not including secured indebtedness permitted under the foregoing exceptions) and the value (as defined below) of all sale and leaseback transactions (as defined below) existing at such time (other than sale and leaseback transactions (i) which, if a lien, would have been permitted under the third or fourth bullet points above or (ii) as to which application of amounts have been made in accordance with “— Limitation on Sale and Leaseback Transactions” below), does not at the time such indebtedness is incurred exceed 5% of consolidated net tangible assets (as defined below), as shown on our most recent audited consolidated balance sheet preceding the date of determination. For purposes of this “Limitation on Liens” covenant, subsidiary does not include a project finance subsidiary (as defined below).

Limitation on Sale and Leaseback Transactions. We will not, and we will not permit any subsidiary to, engage in a sale and leaseback transaction of any principal property unless the net proceeds of such sale are at least equal to the fair value of such principal property (as determined by our board of directors) and either:

- we or such subsidiary would be entitled under the indenture to incur indebtedness secured by a lien on the principal property to be leased, without equally and ratably securing the notes, pursuant to the exceptions provided in the third and fourth bullet points of the second sentence of “— Limitations on Liens” above, or
- within 120 days after the sale or transfer of the principal property, we apply an amount not less than the fair value of such property:
 - to the payment or other retirement of our long-term indebtedness or long-term indebtedness of a subsidiary, in each case ranking senior to or on parity with the notes, or
 - to the purchase at not more than the fair value of principal property (other than that involved in such sale and leaseback transaction).

For purposes of this “Limitation on Sale and Leaseback Transactions” covenant, subsidiary does not include a project finance subsidiary.

Defined Terms.

“*Capital lease*” means a lease that, in accordance with accounting principles generally accepted in the United States, would be recorded as a capital lease on the balance sheet of the lessee.

“*Consolidated net tangible assets*” means the total amount of our assets, including the assets of our subsidiaries, less, without duplication:

- total current liabilities (excluding indebtedness due within 12 months),
- all reserves for depreciation and other asset valuation reserves, but excluding reserves for deferred federal income taxes,
- all intangible assets such as goodwill, trademarks, trade names, patents and unamortized debt discount and expense carried as an asset, and
- all appropriate adjustments on account of minority interests of other persons holding common stock of any subsidiary, all as reflected in our most recent audited consolidated balance sheet preceding the date of such determination.

“Equity interests” means any capital stock, partnership, joint venture, member or limited liability or unlimited liability company interest, beneficial interest in a trust or similar entity or other equity interest or investment of whatever nature.

“Indebtedness,” as applied to us or any subsidiary, means bonds, debentures, notes and other instruments or arrangements representing obligations created or assumed by us or any such subsidiary, including any and all:

- obligations for money borrowed, other than unamortized debt discount or premium,
- obligations evidenced by a note or similar instrument given in connection with the acquisition of any business, properties or assets of any kind,
- obligations as lessee under a capital lease, and
- amendments, renewals, extensions, modifications and refundings of any such indebtedness or obligation listed in the three immediately preceding bullet points.

All indebtedness secured by a lien upon property owned by us or any subsidiary and upon which indebtedness we or any such subsidiary customarily pays interest, although we or any such subsidiary has not assumed or become liable for the payment of such indebtedness, is also deemed to be indebtedness of us or any such subsidiary. All indebtedness for borrowed money incurred by other persons which is directly guaranteed as to payment of principal by us or any subsidiary will for all purposes of the indenture be deemed to be indebtedness of us or any such subsidiary, but no other contingent obligation of us or any such subsidiary in respect of indebtedness incurred by other persons shall be deemed indebtedness of us or any such subsidiary.

“Lien” means any mortgage, deed of trust, pledge, hypothecation, assignment, deposit arrangement, charge, security interest, encumbrance or lien of any kind whatsoever (including any capital lease).

“Non-recourse debt” means (i) any indebtedness for borrowed money incurred by any project finance subsidiary to finance the acquisition, improvement, installation, design, engineering, construction, development, completion, maintenance or operation of, or otherwise to pay costs and expenses relating to or providing financing for, any project, which indebtedness for borrowed money does not provide for recourse against us or any of our subsidiaries (other than a project finance subsidiary and such recourse as exists under a performance guaranty) or any property or asset of us or any of our subsidiaries (other than equity interests in, or the property or assets of, a project finance subsidiary and such recourse as exists under a performance guaranty) and (ii) any refinancing of such indebtedness for borrowed money that does not increase the outstanding principal amount thereof (other than to pay costs incurred in connection therewith and the capitalization of any interest or fees) at the time of the refinancing or increase the property subject to any lien securing such indebtedness for borrowed money or otherwise add additional security or support for such indebtedness for borrowed money.

“Performance guaranty” means any guaranty issued in connection with any non-recourse debt that (i) if secured, is secured only by assets of or equity interests in a project finance subsidiary, and (ii) guarantees to the provider of such non-recourse debt or any other person (a) performance of the improvement, installation, design, engineering, construction, acquisition, development, completion, maintenance or operation of, or otherwise affects any such act in respect of, all or any portion of the project that is financed by such non-recourse debt, (b) completion of the minimum agreed equity or other contributions or support to the relevant project finance subsidiary, or (c) performance by a project finance subsidiary of obligations to persons other than the provider of such non-recourse debt.

“Principal property” means any natural gas distribution property, natural gas pipeline or gas processing plant located in the United States, except any such property that in the opinion of our board of directors is not of material importance to the total business conducted by us and our consolidated subsidiaries. *“Principal property”* shall not include any oil or gas property or the production or proceeds of production from an oil or gas producing property or

the production or any proceeds of production of gas processing plants or oil or gas or petroleum products in any pipeline or storage field.

“Project finance subsidiary” and “project finance subsidiaries” means any of our subsidiaries designated by us whose principal purpose is to incur non-recourse debt and/or construct, lease, own or operate the assets financed thereby, or to become a direct or indirect partner, member or other equity participant or owner in a person created for such purpose, and substantially all the assets of which subsidiary or person are limited to (x) those assets being financed (or to be financed), or the operation of which is being financed (or to be financed), in whole or in part by non-recourse debt, or (y) equity interests in, or indebtedness or other obligations of, one or more other such subsidiaries or persons, or (z) indebtedness or other obligations of us or our subsidiaries or other persons. At the time of designation of any project finance subsidiary, the sum of the net book value of the assets of such subsidiary and the net book value of the assets of all other project finance subsidiaries then existing shall not in the aggregate exceed 10 percent of the consolidated net tangible assets.

“Sale and leaseback transaction” means any arrangement entered into by us or any subsidiary with any person providing for the leasing to us or any subsidiary of any principal property (except for temporary leases for a term, including any renewal thereof, of not more than three years and except for leases between us and a subsidiary or between subsidiaries), which principal property has been or is to be sold or transferred by us or such subsidiary to such person.

“Significant subsidiary” means any subsidiary of ours, other than a project finance subsidiary, that is a “significant subsidiary” as defined in Rule 1-02 of Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934, as such regulation is in effect on the date of issuance of the notes.

“Subsidiary” of any entity means any corporation, partnership, joint venture, limited liability company, trust or estate of which (or in which) more than 50% of (i) the issued and outstanding capital stock having ordinary voting power to elect a majority of the board of directors of such corporation (irrespective of whether at the time capital stock of any other class or classes of such corporation shall or might have voting power upon the occurrence of any contingency), (ii) the interest in the capital or profits of such limited liability company, partnership, joint venture or other entity or (iii) the beneficial interest in such trust or estate is at the time directly or indirectly owned or controlled by such entity, by such entity and one or more of its other subsidiaries or by one or more of such entity’s other subsidiaries.

“Value” means, with respect to a sale and leaseback transaction, as of any particular time, the amount equal to the greater of (1) the net proceeds from the sale or transfer of the property leased pursuant to such sale and leaseback transaction or (2) the fair value, in the opinion of our board of directors, of such property at the time of entering into such sale and leaseback transaction, in either case divided first by the number of full years of the term of the lease and then multiplied by the number of full years of such term remaining at the time of determination, without regard to any renewal or extension options contained in the lease.

Payment and Paying Agent. We have designated the trustee as the sole paying agent for the Senior Notes.

Events of Default. Each of the following is an event of default under the indenture with respect to the Senior Notes; provided, however, that the event of default described in the fourth bullet point below will terminate pursuant to the termination provision of the indenture and will no longer be applicable to the notes on and after the termination date referred to under “Restrictive Covenants” above:

- our failure to pay principal or premium, if any, on the notes when due,
- our failure to pay any interest on the notes for 30 days,
- our failure to perform, or our breach in any material respect of, any other covenant or warranty in the indenture, other than a covenant or warranty included in the indenture solely for the benefit of another series of our debt securities issued under the indenture, for 90 days after either the trustee or holders of at least 25% in principal amount of the outstanding notes of that series have given us written notice of the breach in the manner required by the indenture,
- the default by us or any subsidiary, other than a project finance subsidiary, of ours in the payment, when due, after the expiration of any applicable grace period, of principal of indebtedness for money borrowed, other than non-recourse debt, in the aggregate principal amount then outstanding of \$50 million or more, or acceleration of any indebtedness for money borrowed in such aggregate principal amount so that it becomes due and payable prior to the date on which it would otherwise have become due and payable and such acceleration is not rescinded or such default is not cured within 30 days after notice to us in accordance with the indenture, and
- specified events involving bankruptcy, insolvency or reorganization,

provided, however, that no event described in the third, fourth or fifth bullet points above will be an event of default until an officer of the trustee, assigned to and working in the trustee's corporate trust department, has actual knowledge of the event or until the trustee receives written notice of the event at its corporate trust office, and the notice refers to the notes generally, us or the indenture. (Section 501)

If an event of default occurs and is continuing with respect to the notes, either the trustee or the holders of at least 25% in principal amount of the outstanding notes may declare the principal amount of the notes due and immediately payable. To declare the principal amount of the notes due and immediately payable, the trustee or the holders must deliver a notice that satisfies the requirements of the indenture. Upon a declaration by the trustee or the holders, we will be obligated to pay the principal amount of the notes.

This right does not apply if an event of default described in the fifth bullet point above occurs. If one of the events of default described in the fifth bullet point above occurs and is continuing, the notes then outstanding under the indenture shall be due and payable immediately.

After any declaration of acceleration of the notes, but before a judgment or decree for payment, the holders of a majority in principal amount of the outstanding notes may, under certain circumstances, rescind and annul the declaration of acceleration if all events of default, other than the non-payment of principal, have been cured or waived as provided in the indenture. (Section 502)

If an event of default occurs and is continuing, the trustee will generally have no obligation to exercise any of its rights or powers under the indenture at the request or direction of any of the holders, unless the holders offer reasonable indemnity to the trustee. (Section 603) The holders of a majority in principal amount of the outstanding notes will generally have the right to direct the time, method and place of conducting any proceeding for any remedy available to the trustee or exercising any trust or power conferred on the trustee for the notes, provided that:

- the direction is not in conflict with any law or the indenture,
- the trustee may take any other action it deems proper which is not inconsistent with the direction, and
- the trustee will generally have the right to decline to follow the direction if an officer of the trustee determines, in good faith, that the proceeding would involve the trustee in personal liability or would otherwise be contrary to applicable law. (Section 512)

A holder of a note may only pursue a remedy under the indenture if:

- the holder has previously given the trustee written notice of a continuing event of default for the notes,
- holders of at least 25% in principal amount of the outstanding notes have made a written request to the trustee to pursue that remedy,
- the holders have offered reasonable indemnity to the trustee,
- the trustee fails to pursue that remedy within 60 days after receipt of the notice, request and offer of indemnity, and
- during that 60-day period, the holders of a majority in principal amount of the notes do not give the trustee a direction inconsistent with the request. (Section 507)

However, these limitations do not apply to a suit by a holder of a note demanding payment of the principal, premium, if any, or interest on a note on or after the date the payment is due. (Section 508)

We will be required to furnish to the trustee annually a statement by some of our officers regarding our performance or observance of any of the terms of the indenture and specifying all of our known defaults, if any. (Section 1004)

Defeasance. If we deposit with the trustee funds or government securities sufficient to make payments on the notes on the dates those payments are due and payable, then, at our option, either of the following will occur:

- we will be discharged from our obligations with respect to the notes (“legal defeasance”), or
- we will no longer have any obligation to comply with the restrictive covenants under the indenture, and the related events of default in the third and fourth bullet points under “— Events of Default” above and the restrictions described under “— Consolidation, Merger and Sale of Assets” below will no longer apply to us, but some of our other obligations under the indenture and the notes, including our obligation to make payments on those notes, will survive.

If we defease the notes, the holders of the notes will not be entitled to the benefits of the indenture, except for our obligations to:

- register the transfer or exchange of the notes,
- replace mutilated, destroyed, lost or stolen notes, and
- maintain paying agencies and hold moneys for payment in trust.

We will be required to deliver to the trustee an opinion of counsel that the deposit and related defeasance would not cause the holders of the notes to recognize gain or loss for federal income tax purposes and that the holders would be subject to federal income tax on the same amounts, in the same manner and at the same times as would have been the case if the deposit and related defeasance had not occurred. If we elect legal defeasance, that opinion of counsel must be based upon a ruling from the United States Internal Revenue Service or a change in law to that effect. (Sections 1401, 1402, 1403 and 1404).

Consolidation, Merger and Sale of Assets

Under the indenture, we may not consolidate with or merge into, or convey, transfer or lease our properties and assets substantially as an entirety, to any person, referred to as a “successor person,” and we may not permit any person to consolidate with or merge into, or convey, transfer or lease its properties and assets substantially as an entirety to us, unless:

- the successor person is a corporation, partnership, trust or other entity organized and validly existing under the laws of the United States of America or any state thereof or the District of Columbia,
- the successor person expressly assumes our obligations with respect to the debt securities and the indenture,
- immediately after giving effect to the transaction, no event of default, and no event which, after notice or lapse of time or both, would become an event of default, would occur and be continuing, and
- we have delivered to the trustee the certificates and opinions required under the indenture. (Section 801)

As used in the indenture, the term “corporation” means a corporation, association, company, joint-stock company or business trust.

Exchange and Transfer of the Senior Notes. The notes were issued in registered form, without coupons, in denominations of integral multiples of \$1,000. Holders may present notes for exchange or for registration of transfer at the office of the security registrar or at the office of any transfer agent we designate for that purpose. The security registrar or designated transfer agent will exchange or transfer the notes if it is satisfied with the documents of title and identity of the person making the request. We will not charge a service charge for any exchange or registration of transfer of notes. However, we may require payment of a sum sufficient to cover any tax or other governmental charge payable for the exchange or registration of transfer. The trustee will serve as the security registrar. (Section 305) At any time we may:

- designate additional transfer agents,
- rescind the designation of any transfer agent, or
- approve a change in the office of any transfer agent.

However, we are required to maintain a transfer agent in each place of payment for the Senior Notes at all times. (Sections 305 and 1002)

In the event we elect to redeem the Senior Notes, neither we nor the trustee will be required to register the transfer or exchange of the Senior Notes:

- during the period beginning at the opening of business 15 days before the day we mail the notice of redemption for such notes and ending at the close of business on the day the notice is mailed, or
- if we have selected such notes for redemption, in whole or in part, except for the unredeemed portion of such notes. (Section 305)

Regarding the Trustee. The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, National Association, is the trustee, security registrar and paying agent under the Indenture for the Senior Notes. Our affiliates maintain brokerage relationships and a rabbi trust with the trustee and its affiliates.

Book-Entry Delivery and Settlement. The Senior Notes were issued in the form of one or more permanent global notes in definitive, fully registered, book-entry form. The global notes were either deposited with or on behalf of The Depository Trust Company and registered in the name of Cede & Co., as nominee of DTC, or remained in the custody of the trustee in accordance with the FAST Balance Certificate Agreement between DTC and the trustee. Beneficial interests in the global notes are represented through book-entry accounts of financial institutions acting on behalf of beneficial owners as direct and indirect participants in DTC. Investors may hold interests in the global notes through DTC either directly if they are participants in DTC or indirectly through organizations that are participants in DTC. DTC has advised us as follows:

- DTC is a limited-purpose trust company organized under the New York Banking Law, a “banking organization” within the meaning of the New York Banking Law, a member of the Federal Reserve System, a “clearing corporation” within the meaning of the New York Uniform Commercial Code and a “clearing agency” registered under Section 17A of the Securities Exchange Act of 1934.
- DTC holds securities that its participants deposit with DTC and facilitates the settlement among participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in participants’ accounts, thereby eliminating the need for physical movement of securities certificates.
- Direct participants include securities brokers and dealers, banks, trust companies, clearing corporations and other organizations.
- DTC is owned by a number of its direct participants and by The New York Stock Exchange, Inc., the American Stock Exchange LLC and the Financial Industry Regulatory Authority, Inc.
- Access to the DTC system is also available to others such as securities brokers and dealers, banks and trust companies that clear through or maintain a custodial relationship with a direct participant, either directly or indirectly.
- The rules applicable to DTC and its direct and indirect participants are on file with the SEC.

We have provided the description of the operations and procedures of DTC herein solely as a matter of convenience. These operations and procedures are solely within the control of DTC and are subject to change by it from time to time. Neither we nor the underwriters or the trustee takes any responsibility for these operations or procedures, and you are urged to contact DTC or its participants directly to discuss these matters.

We expect that under procedures established by DTC:

- upon deposit of the global notes with DTC or its custodian, DTC will credit on its internal system the accounts of direct participants designated by the underwriters with portions of the principal amounts of the global notes; and
- ownership of the notes will be shown on, and the transfer of ownership thereof will be effected only through, records maintained by DTC or its nominee, with respect to interests of direct participants, and the records of direct and indirect participants, with respect to interests of persons other than participants.

The laws of some jurisdictions may require that purchasers of securities take physical delivery of those securities in definitive form. Accordingly, the ability to transfer interests in the notes represented by a global note to those persons may be limited. In addition, because DTC can act only on behalf of its participants, who in turn act on behalf of persons who hold interests through participants, the ability of a person having an interest in notes represented by a global note to pledge or transfer those interests to persons or entities that do not participate in DTC’s system, or otherwise to take actions in respect of such interest, may be affected by the lack of a physical definitive security in respect of such interest.

So long as DTC or its nominee is the registered owner of a global note, DTC or that nominee will be considered the sole owner or holder of the notes represented by that global note for all purposes under the indenture and under the notes. Except as provided below, owners of beneficial interests in a global note will not be entitled to have notes represented by that global note registered in their names, will not receive or be entitled to receive physical delivery of certificated notes and will not be considered the owners or holders thereof under the indenture or under the notes for any purpose, including with respect to the giving of any direction, instruction or approval to

the trustee. Accordingly, each holder owning a beneficial interest in a global note must rely on the procedures of DTC and, if that holder is not a direct or indirect participant, on the procedures of the participant through which that holder owns its interest, to exercise any rights of a holder of notes under the indenture or the global note.

Neither we nor the trustee will have any responsibility or liability for any aspect of the records relating to or payments made on account of notes by DTC, or for maintaining, supervising or reviewing any records of DTC relating to the notes.

Payments on the notes represented by the global notes will be made to DTC or its nominee, as the case may be, as the registered owner thereof. We expect that DTC or its nominee, upon receipt of any payment on the notes represented by a global note, will credit participants' accounts with payments in amounts proportionate to their respective beneficial interests in the global note as shown in the records of DTC or its nominee. We also expect that payments by participants to owners of beneficial interests in the global note held through such participants will be governed by standing instructions and customary practice as is now the case with securities held for the accounts of customers registered in the names of nominees for such customers. The participants will be responsible for those payments.

Certificated Notes. Certificated notes will be issued to each person that DTC identifies as the beneficial owner of the notes represented by the global notes, upon surrender by DTC of the global notes, if (i) DTC or any successor depository (the "depository") notifies us that it is no longer willing or able to act as a depository for the global notes or DTC ceases to be registered as a clearing agency under the Securities Exchange Act of 1934 and a successor depository is not appointed within 90 days of such notice or cessation, (ii) we, at our option and subject to DTC procedures, notify the trustee in writing that we elect to cause the issuance of notes in definitive form under the indenture or (iii) upon the occurrence of certain other events as provided pursuant to the indenture.

CENTERPOINT ENERGY, INC.
2022 LONG TERM INCENTIVE PLAN
PERFORMANCE AWARD AGREEMENT
FOR CHAIR OF BOARD, PRESIDENT & CEO
JANUARY 1, 20XX – DECEMBER 31, 20XX PERFORMANCE CYCLE

Pursuant to this Performance Award Agreement (the “Award Agreement”), **CENTERPOINT ENERGY, INC.** (the “Company”) hereby grants to <first_name> <last_name>, an employee of the Company, this Performance Award (the “Award”) covering the target number of shares, <shares_awarded>, of Common Stock (the “Target Shares”) pursuant to the **CENTERPOINT ENERGY, INC. 2022 LONG TERM INCENTIVE PLAN** (the “Plan”). The number of Target Shares shall be subject to adjustment as provided in Section 14 of the Plan, conditioned upon the Company’s achievement of the Performance Goals over the course of the 20XX – 20XX Performance Cycle, and subject to the following terms and conditions:

1. Relationship to the Plan. The Award is subject to all of the terms, conditions and provisions of the Plan in effect on the date hereof and administrative interpretations thereunder, if any, adopted by the Committee. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, it is hereby acknowledged and agreed that the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant herein also include the heirs or other legal representatives of the Participant.

2. Definitions. Except as defined herein, capitalized terms shall have the same meanings ascribed to them under the Plan. For purposes of this Award Agreement:

“**Achievement Percentage**” means the percentage of achievement determined by the Committee after the end of the Performance Cycle in accordance with Section 4 that reflects the extent to which the Company achieved the Performance Goals during the Performance Cycle.

“**Cause**” means the Participant's (a) gross negligence in the performance of his or her duties, (b) intentional and continued failure to perform his or her duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Subsidiaries (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of the Participant will be deemed “intentional” only if done or omitted to be done by the Participant not in good faith and without reasonable belief that his or her action or omission was in the best interest of the Company, and no act or failure to act on the part of the Participant will be deemed “intentional” if it was due primarily to an error in judgment or negligence.

“**Change in Control Closing Date**” means the date a Change in Control is consummated during the Performance Cycle.

“**Change in Control Payment Date**” means the following:



(a) If the Change in Control is a Section 409A Change in Control, then the Change in Control Payment Date shall be not later than the 70th day after the Change in Control Closing Date; and

(b) If the Change in Control is a Non-Section 409A Change in Control, then the Change in Control Payment Date shall be a date following the last day of the Performance Cycle but no later than March 15th of the calendar year following the calendar year in which occurs the last day of the Performance Cycle; provided, however, in the case of the Participant's death or Separation from Service after the Change in Control but prior to such date, all shares not previously paid shall be paid not later than the 70th day after the Participant's Separation from Service date except as otherwise provided in Section 7(c).

"Covered Termination" means a Separation from Service that occurs within two years after the date upon which a Change in Control occurs and that does not result from any of the following:

- (a) death;
- (b) Disability;
- (c) involuntary termination for Cause; or
- (d) resignation by the Participant, unless such resignation is for Good Reason.

"Disability" means that the Participant is eligible for and in receipt of benefits under the Company's long-term disability plan.

"Employment" means employment with the Company or any of its Subsidiaries.

"Good Reason" means any one or more of the following events:

(a) a failure to maintain the Participant in the position, or a substantially equivalent position, with the Company and/or a Subsidiary, as the case may be, which the Participant held immediately prior to the Change in Control;

(b) a significant adverse change in the authorities, powers, functions, responsibilities, duties, or reporting structure which the Participant held immediately prior to the Change in Control;

(c) a significant reduction in the Participant's annual base salary as in effect immediately prior to the date on which a Change in Control occurs;

(d) a significant reduction in the Participant's qualified retirement benefits, nonqualified benefits and welfare benefits provided to the Participant immediately prior to the date on which a Change in Control occurs; provided, however, that a contemporaneous diminution of or reduction in qualified retirement benefits and/or welfare benefits which is of general application and which uniformly and contemporaneously reduces or diminishes the benefits of all covered

employees shall be ignored and not be considered a reduction in remuneration for purposes of this paragraph (d);

(e) a significant reduction in the Participant's overall compensation opportunities (as contrasted with overall compensation actually paid or awarded) under a short-term incentive plan, a long-term incentive plan or other equity plan (or in such substitute or alternative plans) from that provided to the Participant immediately prior to the date on which a Change in Control occurs;

(f) a change in the location of the Participant's principal place of employment with the Company by more than 50 miles from the location where the Participant was principally employed immediately prior to the date on which a Change in Control occurs; or

(g) a failure by the Company to provide directors and officers liability insurance covering the Participant comparable to that provided to the Participant immediately prior to the date on which a Change in Control occurs;

provided, however, that no later than 30 days after learning of the action (or inaction) described herein as the basis for a termination of employment for Good Reason, the Participant shall advise the Company in writing that the action (or inaction) constitutes grounds for a termination of his or her Employment for Good Reason, in which event the Company shall have 30 days (the "Cure Period") to correct such action (or inaction). If such action (or inaction) is not corrected prior to the end of the Cure Period, then the Participant may terminate his or her Employment with the Company for Good Reason within the 30-day period following the end of the Cure Period by giving written notice to the Company. If such action (or inaction) is corrected before the end of the Cure Period, then the Participant shall not be entitled to terminate his or her Employment for Good Reason as a result of such action (or inaction).

"Non-Section 409A Change in Control" means a Change in Control that is not a Section 409A Change in Control.

"Performance Cycle" means the period beginning on January 1, 20XX and ending on December 31, 20XX.

"Performance Goal" means the standards established by the Committee for the Performance Cycle to determine in whole or in part the number of Vested Shares pursuant to Section 4, which are specified in a separate document provided with this Award Agreement and made a part hereof for all purposes.

"Retirement" means a Separation from Service for any reason other than by the Company for Cause or due to death or Disability, (a) on or after the attainment of age 55 and with a sum of age and years of Employment of 65 or greater or (b) with at least five years of Employment in the role of Chief Executive Officer of the Company; *provided, however,* that a Separation from Service will not qualify as a "Retirement" unless the following conditions are satisfied:

(a) the Participant provides to the Company a comprehensive transition plan for the Participant's role and responsibilities and such plan is approved and accepted by the Company in its sole discretion;

(b) the Participant provides the Company at least three months' written notice of the Participant's Retirement or, if the Participant is a Section 16 Officer, reasonable advance written notice (as determined by the Committee) of the Participant's Retirement to the Chief Human Resources Officer; and

(c) If the Participant is a Section 16 Officer, the Committee approves, in its sole discretion, the Participant's Retirement under this Award Agreement prior to the Participant's Separation from Service.

"Sale of a Subsidiary" means, with respect to the Subsidiary for which the Participant is performing services at the time of the applicable event, the occurrence of any of the following events:

(a) A change in the ownership of such Subsidiary, as determined in accordance with Treasury Regulation § 1.409A-3(i)(5)(v) or

(b) A change in the ownership of a substantial portion of such Subsidiary's assets, as determined in accordance with Treasury Regulation § 1.409A-3(i)(5)(vii).

If the Subsidiary is not a corporation, the above referenced Treasury Regulations may be applied by analogy in accordance with guidance issued under Section 409A.

"Section 16 Officer" means a Participant who is an "officer" within the meaning of Section 16 of the Exchange Act as of the date notice of the Participant's Retirement is provided to the Chief Human Resources Officer.

"Section 409A" means Code Section 409A and the Treasury regulations and guidance issued thereunder.

"Section 409A Change in Control" means a Change in Control that satisfies the requirements of a change in control for purposes of Code Section 409A(a)(2)(A)(v) and the Treasury regulations and guidance issued thereunder.

"Separation from Service" means a separation from service with the Company or any of its Subsidiaries within the meaning of Treasury Regulation § 1.409A-1(h) (or any successor regulation).

"Target Shares" means the actual number of shares originally granted to the Participant as specified in this Award Agreement.

"Vested Shares" means the shares of Common Stock actually distributable to the Participant following the Participant's satisfaction of the vesting provisions of Section 5 and, if applicable, the determination by the Committee of the extent to which the Company has achieved the Performance Goals for the Performance Cycle pursuant to Section 4.

3. Establishment of Award Account. The grant of Target Shares pursuant to this Award Agreement shall be implemented by a credit to a bookkeeping account maintained by the Company evidencing the Participant's unfunded and unsecured right to receive shares of Common Stock of the Company, which right shall be subject to the terms, conditions and restrictions set forth in the Plan and to the further terms, conditions and restrictions set forth in this Award Agreement. Except as otherwise provided in this Award Agreement, the Target Shares of Common Stock credited to the Participant's bookkeeping account may not be sold, assigned,

transferred, pledged or otherwise encumbered until the Participant has been registered as a holder of shares of Common Stock on the records of the Company as provided in Section 6 or 7 of this Award Agreement.

4. Award Opportunity.

(a) Except as otherwise provided in Section 5(b)(ii) or Section 6, the Participant's Vested Shares shall be the product of the number of Target Shares and the Achievement Percentage that is based upon the Committee's determination of whether and to what extent the Performance Goals have been achieved during the Performance Cycle.

(b) No later than 60 days after the close of the Performance Cycle, the Committee shall determine the extent to which each Performance Goal has been achieved. If the Company has performed at or above the threshold level of achievement for a Performance Goal, the Achievement Percentage shall be between X% and X%. In no event shall the Achievement Percentage exceed X%. Upon completing its determination of the level at which the Performance Goals have been achieved, the Committee shall notify the Participant, in the form and manner as determined by the Committee, of the number of Vested Shares that will be issued to the Participant pursuant to Section 5.

5. Vesting of Shares.

(a) Unless earlier forfeited in accordance with Section 5(b)(i) or unless earlier vested in accordance with Section 5(b)(ii), Section 6(b), Section 6(c) or Section 6(d), the Participant's right to receive shares pursuant to this Award Agreement, if any, shall vest on the last day of the Performance Cycle (with the number of shares, if any, based on the Committee's determination that each Performance Goal has been met (as provided in Section 4)). As soon as administratively practicable, but in no event later than 70 days, after the close of the Performance Cycle, the Committee shall notify the Participant as required by Section 4 of the level at which the Performance Goals established for the Performance Cycle have been achieved.

(b) If the Participant's Separation from Service date occurs prior to the close of the Performance Cycle and the occurrence of a vesting event described in Section 6(b), 6(c), or 6(d) (in connection with a Change in Control or a Sale of a Subsidiary), then the applicable of the following clauses shall apply with respect to the Target Shares subject to this Award Agreement:

(i) Forfeiture of Entire Award. Except as otherwise provided under Section (b)(ii) or (b)(iii), if the Participant's Employment is terminated such that the Participant has a Separation from Service by the Company or any of its Subsidiaries or by the Participant, then the Participant's right to receive any Target Shares shall be forfeited in its entirety as of the date of such Separation from Service.

(ii) Death or Disability. If the Participant's Employment is terminated due to death or Disability, the Participant's right to receive the Target Shares shall vest on the date of such Separation from Service. The Participant's right to receive any additional shares pursuant to this Award Agreement shall be forfeited at such time.

(iii) Retirement. If the Participant's Employment is terminated due to Retirement, then the Award shall remain outstanding and the Participant shall be vested in the right to receive the number of Vested Shares based upon the Committee's determination of achievement of Performance Goals as provided in Section 4, *provided, however*, that if the Participant's Retirement occurs before the first anniversary of the beginning of the Performance Cycle, the number of Vested Shares such Participant shall entitled to receive shall be pro-rated by multiplying (x) the number of Vested Shares the Participant would have otherwise received under this Section 5(b)(iii) by (y) a fraction, the numerator of which is the number of days elapsed in the Performance Cycle as of the date of the Participant's Separation from Service and the denominator of which is the total number of days in the Performance Cycle.

(c) In accordance with the provisions of this Section 5, the Vested Shares shall be distributed as provided in Section 7 hereof.

6. Change in Control.

(a) Assumption or Substitution. In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror"), may, without the Participant's consent, either assume or continue the Company's rights and obligations under this Award Agreement or provide a substantially equivalent award in substitution for the shares subject to this Award.

(b) Vesting Upon a Change in Control. Notwithstanding anything herein to the contrary and without regard to the Performance Goals, if (i) there is a Change in Control during the Performance Cycle and prior to the Participant's Separation from Service (other than a Separation from Service due to Retirement) and (ii) the Acquiror does not assume or continue this Award or provide a substantially equivalent award in substitution for this Award pursuant to Section 6(a), then upon the Change in Control Closing Date, the Participant's right to receive the Target Shares shall vest. Notwithstanding the foregoing, in the event the Change in Control occurs after the Participant has had a Separation from Service due to Retirement and such Retirement occurred before the first anniversary of the beginning of the Performance Cycle, the Target Shares such Participant shall receive under this Section 6(b) shall be pro-rated based on the number of days that elapsed in the Performance Cycle as of the date of the Participant's Separation from Service over the total number of days in the Performance Cycle.

(c) Vesting Upon a Covered Termination. Notwithstanding anything herein to the contrary and without regard to the Performance Goals, if the Participant experiences a Covered Termination during the Performance Cycle, then, upon the date of the Covered Termination, the Participant's right to receive the Target Shares shall vest.

(d) Vesting Upon the Sale of a Subsidiary. Notwithstanding anything herein to the contrary and without regard to the Performance Goals, if (i) a Sale of a Subsidiary with respect to the Participant occurs during the Performance Cycle and (ii) the Participant's employment with the Company and all Subsidiaries (other than any entity that ceases to be a Subsidiary as a result of the Sale of a Subsidiary) ceases upon and in connection with

such Sale of a Subsidiary, then upon such Sale of a Subsidiary, the Participant's right to receive the Target Shares shall vest in the proportion of the number of days elapsed in the Performance Cycle as of the date of the Sale of a Subsidiary by the total number of days in the Performance Cycle. The Participant's right to receive any additional shares pursuant to this Award Agreement shall be forfeited at such time.

(e) Distributions Upon a Change in Control or Sale of a Subsidiary. If the Participant is entitled to a benefit pursuant to Section 6(b), 6(c), or 6(d) hereof, then this Award shall be settled by the distribution to the Participant of:

(i) shares of Common Stock equal to the Target Shares (or such pro-rated amount as set forth in Section 6(b) or 6(d), if applicable); *plus*

(ii) Dividend Equivalents on such shares of Common Stock in the form of shares of Common Stock (rounded up to the nearest whole share) for the period commencing at the beginning of the Performance Cycle and ending on the date immediately preceding the date of the distribution.

In lieu of the foregoing distribution in shares, the Committee, in its sole discretion, may direct that such distribution be made to the Participant in a lump cash payment equal to:

(x) the product of (A) the Fair Market Value per share of Common Stock on the date immediately preceding the date of the distribution and (B) the Target Shares (or such pro-rated amount as set forth in Section 6(b) or 6(d), if applicable); *plus*

(y) Dividend Equivalents on such shares of Common Stock for the period commencing at the beginning of the Performance Cycle and ending on the date immediately preceding the date of the distribution.

Such distribution, whether in the form of shares of Common Stock or, if directed by the Committee, in cash, shall satisfy the rights of the Participant and the obligations of the Company under this Award Agreement in full.

(f) Timing of Distribution.

(i) *No Assumption or Substitution.* If the Participant is entitled to a benefit pursuant to Section 6(b), distributions shall be made in accordance with Section 6(e) on the Change in Control Payment Date.

(ii) *Covered Termination.* If the Participant is entitled to a benefit pursuant to Section 6(c) on account of a Covered Termination, distributions shall be made in accordance with Section 6(e) not later than the 70th day after the Participant's Separation from Service date except as otherwise provided in Section 7(c).

(iii) *Sale of a Subsidiary.* If the Participant is entitled to a benefit pursuant to Section 6(d), distributions shall be made in accordance with Section 6(e) not later than the 70th day after the date the Sale of a Subsidiary is consummated.

7. Distribution of Vested Shares.

(a) If the Participant's right to receive shares pursuant to this Award Agreement has vested pursuant to Section 5(a) or Section 5(b)(iii), a number of shares of Common Stock equal to the number of Vested Shares shall be distributed no later than March 15th of the calendar year following the calendar year in which occurs the last day of the Performance Cycle.

(b) If the Participant's right to receive shares pursuant to this Award Agreement has vested pursuant to Section 5(b)(ii), a number of shares of Common Stock equal to the number of Vested Shares shall be distributed not later than the 70th day after the Participant's Separation from Service date except as otherwise provided in Section 7(c).

(c) With respect to any benefits payable hereunder upon the Participant's Separation from Service (other than a Separation from Service due to the Participant's death), if as of the Participant's Separation from Service date, the Participant is a "specified employee" (within the meaning of Section 409A(a)(2)(B)), then such benefits shall not be distributed until the date that is the earlier of (i) the second business day following the end of the six-month period commencing on the Participant's Separation from Service date or (ii) the Participant's date of death, if death occurs during such six-month period.

(d) The Company shall have the right to withhold applicable taxes from any such distribution of Vested Shares or from other compensation payable to the Participant at the time of such vesting and distribution pursuant to Section 11 of the Plan (but subject to compliance with the requirements of Section 409A, if applicable).

(e) Upon distribution of the Vested Shares pursuant to this Section 7, the Participant shall also be entitled to receive Dividend Equivalents for the Vested Shares for the period after the commencement of the Performance Cycle but prior to the date the Vested Shares are delivered to the Participant (in accordance with the requirements of Section 409A, to the extent applicable).

8. Confidentiality. The Participant agrees that the terms of this Award Agreement are confidential and that any disclosure to anyone for any purpose whatsoever (save and except disclosure to financial institutions as part of a financial statement, financial, tax and legal advisors, or as required by law) by the Participant or his or her agents, representatives, heirs, children, spouse, employees or spokespersons shall be a breach of this Award Agreement and the Company may elect to revoke the grant made hereunder, seek damages, plus interest and reasonable attorneys' fees, and take any other lawful actions to enforce this Award Agreement.

9. Participant Obligations.

(a) Confidentiality. The Participant acknowledges that in the course of his or her employment with the Company, the Company agrees to provide to the Participant Confidential Information regarding the Company and the Company's business and has previously provided the Participant other such Confidential Information. In return for this and other consideration, provided under this Award Agreement, the Participant agrees that he or she will not, while employed by the Company and thereafter, disclose or make available to any other person or entity, or use for his own personal gain, any Confidential Information, except for such disclosures as required in the performance of his or her duties

hereunder or as may otherwise be required by law or legal process (in which case the Participant shall notify the Company of such legal or judicial proceeding by a non-governmental party as soon as practicable following his receipt of notice of such a proceeding, and permit the Company to seek to protect its interests and information). Nothing in this Award Agreement, however, limits or precludes Participant from making a good faith voluntary report, charge, complaint, or claim to or providing truthful testimony and documents as required by law or under oath pursuant to a subpoena, court order, or request by the Equal Employment Opportunity Commission, the National Labor Relations Board, the Occupational Safety and Health Administration, the Securities and Exchange Commission or any other federal, state, or local government agency or commission ("Government Agencies"). Participant further understands that this Award Agreement does not limit Participant's ability to communicate with any Government Agencies or otherwise participate in any investigation or proceeding that may be conducted by any Government Agency, including providing documents or other information to the Government Agency, without notice to the Company. For purposes of this Award Agreement, "**Confidential Information**" shall mean any and all information, data and knowledge that has been created, discovered, developed or otherwise become known to the Company or any of its affiliates or ventures or in which property rights have been assigned or otherwise conveyed to the Company or any of its affiliates or ventures, which information, data or knowledge has commercial value in the business in which the Company is engaged, except such information, data or knowledge as is or becomes known to the public without violation of the terms of this Award Agreement. By way of illustration, but not limitation, Confidential Information includes business trade secrets, secrets concerning the Company's plans and strategies, nonpublic information concerning material market opportunities, technical trade secrets, processes, formulas, know-how, improvements, discoveries, developments, designs, inventions, techniques, marketing plans, manuals, records of research, reports, memoranda, computer software, strategies, forecasts, new products, unpublished financial information, projections, licenses, prices, costs, and employee, customer and supplier lists or parts thereof.

The Participant acknowledges notice that under the federal Defend Trade Secrets Act (DTSA), no individual may be held criminally or civilly liable under federal or state trade secret law for a trade secret disclosure that complies with 18 U.S.C. §1833(b) such as a disclosure (i) made in confidence to a federal, state, or local government official, either directly or indirectly, or to an attorney and made solely for the purpose of reporting or investigating a suspected violation of law or (ii) made in a complaint or other document filed in a lawsuit or other adjudicatory proceeding, if such filing is made under seal. Also, under the DTSA, an individual pursuing a legal claim for retaliation by an employer for reporting a suspected violation of the law may disclose a trade secret to his/her attorney and use it in information in the court or adjudicatory proceeding if the individual files any document containing the trade secret under seal and does not disclose the trade secret except to an order of the court or adjudicator.

(b) Return of Property. The Participant agrees that at the time of his or her Separation from Service, he or she will deliver to the Company (and will not keep in his or her possession, recreate or deliver to anyone else) all Confidential Information as well as all other devices, records, data, notes, reports, proposals, lists, correspondence, specifications, drawings, blueprints, sketches, materials, equipment, customer or client lists or information, or any other documents or property (including all reproductions of the

aforementioned items) belonging to the Company or any of its affiliates or ventures, regardless of whether such items were prepared by the Participant.

(c) Non-Solicitation and Non-Competition.

(i) *Non-Solicitation.* For consideration provided under this Award Agreement, including, but not limited to the Company's agreement to provide the Participant with Confidential Information (as defined in Section 9(a)) regarding the Company and the Company's business, the Participant agrees that, while employed by the Company and for one year following his or her Separation from Service, he or she shall not, without the prior written consent of the Company, directly or indirectly, (A) hire or induce, entice or solicit (or attempt to induce, entice or solicit) any employee of the Company or any of its affiliates or ventures to leave the employment of the Company or any of its affiliates or ventures or (B) solicit or attempt to solicit the business of any customer or acquisition prospect of the Company or any of its affiliates or ventures with whom the Participant had any actual contact while employed at the Company.

(ii) *Non-Competition.* For consideration provided under this Award Agreement, including, but not limited to the Company's agreement to provide the Participant with Confidential Information regarding the Company and the Company's business, the Participant agrees that while employed by the Company and for one year following a Separation from Service he or she will not, without the prior written consent of the Company, acting alone or in conjunction with others, either directly or indirectly, engage in any business that is in competition with the Company or accept employment with or render services to such a business as an officer, agent, employee, independent contractor or consultant, or otherwise engage in activities that are in competition with the Company.

(iii) *Restricted Area.* The restrictions contained in this Section 9(c) are limited to a 50-mile radius around any geographical area in which the Company engages (or has definite plans to engage) in operations or the marketing of its products or services at the time of the Participant's Separation from Service.

(iv) *Minnesota Participants.* If the Participant primarily resides and works for the Company in Minnesota when last employed with the Company or any of its affiliates, the post-employment non-competition covenant set forth in Section 9(c)(ii) above shall not apply to the Participant.

(d) Restrictions Reasonable. The Participant acknowledges that the restrictive covenants under this Section 9, for which the Participant received valuable consideration from the Company as provided in this Award Agreement, including, but not limited to the Company's agreement to provide the Participant with Confidential Information regarding the Company and the Company's business are ancillary to otherwise enforceable provisions of this Award Agreement that the consideration provided by the Company gives rise to the Company's interest in restraining the Participant from competing and that the restrictive covenants are designed to enforce the Participant's consideration or return promises under this Award Agreement. Additionally, the Participant acknowledges that these restrictive covenants contain limitations as to time, geographical area, and scope of

activity to be restrained that are reasonable and do not impose a greater restraint than is necessary to protect the goodwill or other legitimate business interests of the Company, including, but not limited to, the Company's need to protect its Confidential Information.

(e) **Violations.** If the Participant violates any provision of this Section 9, the Participant shall not be entitled to receive any amounts that would otherwise be payable to the Participant with respect to this Award, and such amounts shall be forfeited. If the Participant violates any provision of this Section 9 after amounts under this Award have been paid or if the Company learns of the violation after amounts under this Award have been paid, the Participant shall repay to the Company the Common Shares (or the equivalent value thereof determined as of the date of the Company's demand) or the cash received, as the case may be, within thirty (30) days of receiving a demand from the Company for the repayment of the Award. Further, the Company shall be entitled to an award of attorneys' fees incurred with securing any relief hereunder and/or pursuant to a breach or threatened breach of this Section 9.

10. Notices. For purposes of this Award Agreement, notices to the Company shall be deemed to have been duly given upon receipt of written notice by the Corporate Secretary of CenterPoint Energy, Inc., 1111 Louisiana, Houston, Texas 77002, or to such other address as the Company may furnish to the Participant.

Notices to the Participant shall be deemed effectively delivered or given upon personal, electronic, or postal delivery of written notice to the Participant, the place of Employment of the Participant, the address on record for the Participant at the human resources department of the Company, or such other address as the Participant hereafter designates by written notice to the Company.

11. Shareholder Rights. The Participant shall have no rights of a shareholder with respect to the Target Shares, unless and until the Participant is registered as the holder of shares of Common Stock.

12. Successors and Assigns. This Award Agreement shall bind and inure to the benefit of and be enforceable by the Participant, the Company and their respective permitted successors and assigns except as expressly prohibited herein and in the Plan. Notwithstanding anything herein or in the Plan to the contrary, the Target Shares are transferable by the Participant to Immediate Family Members, Immediate Family Member trusts, and Immediate Family Member partnerships pursuant to Section 13 of the Plan.

13. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Company or any Subsidiary or any successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

14. Waiver. Failure of either party to demand strict compliance with any of the terms or conditions hereof shall not be deemed a waiver of such term or condition, nor shall any waiver by either party of any right hereunder at any one time or more times be deemed a waiver of such right at any other time or times. No term or condition hereof shall be deemed to have been waived except by written instrument.

15. Compliance with Section 409A. It is the intent of the Company and the Participant that the provisions of the Plan and this Award Agreement comply with Section 409A and will be interpreted and administered consistent therewith. Accordingly, (a) no adjustment to the Award pursuant to Section 14 of the Plan and (b) no substitutions of the benefits under this Award Agreement, in each case, shall be made in a manner that results in noncompliance with the requirements of Section 409A, to the extent applicable.

16. Modification of Award Agreement. Any modification of this Award Agreement is subject to Section 15 hereof and shall be binding only if evidenced in writing and signed by an authorized representative of the Company.

17. Severability. If any provision of this Award Agreement is, becomes or is deemed to be invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions of the Award Agreement shall not be affected thereby.

CENTERPOINT ENERGY, INC.
2022 LONG TERM INCENTIVE PLAN

FORM OF RESTRICTED STOCK UNIT AWARD AGREEMENT
FOR CHAIR OF BOARD, PRESIDENT & CEO
(with Performance Goals)

Pursuant to this Restricted Stock Unit Award Agreement (“Award Agreement”), **CENTERPOINT ENERGY, INC.** (the “Company”) hereby grants to <first_name> <last_name>, an employee of the Company, on <award_date> (the “Award Date”), a restricted stock unit award of <shares_awarded> units of Common Stock of the Company (the “RSU Award”) pursuant to the **CENTERPOINT ENERGY, INC. 2022 LONG TERM INCENTIVE PLAN** (the “Plan”), conditioned upon the Company’s achievement of the Performance Goals established by the Committee and subject to the terms, conditions and restrictions described in the Plan and as follows:

1. Relationship to the Plan; Definitions. This RSU Award is subject to all of the terms, conditions and provisions of the Plan in effect on the date hereof and administrative interpretations thereunder, if any, adopted by the Committee. Except as defined herein, capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, it is hereby acknowledged and agreed that the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant herein also include the heirs or other legal representatives of the Participant. For purposes of this Award Agreement:

“**Award Date**” means the date this RSU Award is granted to the Participant as specified in this Award Agreement.

“**Cause**” means the Participant’s (a) gross negligence in the performance of his or her duties, (b) intentional and continued failure to perform his or her duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Subsidiaries (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of the Participant will be deemed “intentional” only if done or omitted to be done by the Participant not in good faith and without reasonable belief that his or her action or omission was in the best interest of the Company, and no act or failure to act on the part of the Participant will be deemed “intentional” if it was due primarily to an error in judgment or negligence.

“**Change in Control Closing Date**” means the date a Change in Control is consummated.

“**Change in Control Payment Date**” means the following:

(a) If the Change in Control is a Section 409A Change in Control, then the Change in Control Payment Date shall be not later than the 70th day after the Change in Control Closing Date; and

(b) If the Change in Control is a Non-Section 409A Change in Control, then the Change in Control Payment Date shall be the Vesting Date(s) on which the units are paid under Section 3 hereof for the number of units indicated in Section 3 assuming continuous Employment by the Participant as of such Vesting Date(s); provided, however, in the case of the Participant's death or Separation from Service prior to the Vesting Date(s), all shares not previously paid shall be paid not later than the 70th day after the Participant's Termination Date except as otherwise provided in Section 7.

“Covered Termination” means a Separation from Service that occurs within two years after the date upon which a Change in Control occurs and that does not result from any of the following:

- (a) death;
- (b) Disability;
- (c) involuntary termination for Cause; or
- (d) resignation by the Participant, unless such resignation is for Good Reason.

“Disability” means that the Participant is both eligible for and in receipt of benefits under the Company's long-term disability plan.

“Employment” means employment with the Company or any of its Subsidiaries.

“Good Reason” means any one or more of the following events:

- (a) a failure to maintain the Participant in the position, or a substantially equivalent position, with the Company and/or a Subsidiary, as the case may be, which the Participant held immediately prior to the Change in Control;
- (b) a significant adverse change in the authorities, powers, functions, responsibilities, duties, or reporting structure which the Participant held immediately prior to the Change in Control;
- (c) a significant reduction in the Participant's annual base salary as in effect immediately prior to the date on which a Change in Control occurs;
- (d) a significant reduction in the Participant's qualified retirement benefits, nonqualified benefits and welfare benefits provided to the Participant immediately prior to the date on which a Change in Control occurs; provided, however, that a contemporaneous diminution of or reduction in qualified retirement benefits and/or welfare benefits which is of general application and which uniformly and contemporaneously reduces or diminishes the benefits of all covered employees shall be ignored and not be considered a reduction in remuneration for purposes of this paragraph (d);

(e) a significant reduction in the Participant's overall compensation opportunities (as contrasted with overall compensation actually paid or awarded) under a short-term incentive plan, a long-term incentive plan or other equity plan (or in such substitute or alternative plans) from that provided to the Participant immediately prior to the date on which a Change in Control occurs;

(f) a change in the location of the Participant's principal place of employment with the Company by more than 50 miles from the location where the Participant was principally employed immediately prior to the date on which a Change in Control occurs; or

(g) a failure by the Company to provide directors and officers liability insurance covering the Participant comparable to that provided to the Participant immediately prior to the date on which a Change in Control occurs;

provided, however, that no later than 30 days after learning of the action (or inaction) described herein as the basis for a termination of employment for Good Reason, the Participant shall advise the Company in writing that the action (or inaction) constitutes grounds for a termination of his or her Employment for Good Reason, in which event the Company shall have 30 days (the "Cure Period") to correct such action (or inaction). If such action (or inaction) is not corrected prior to the end of the Cure Period, then the Participant may terminate his or her Employment with the Company for Good Reason within the 30-day period following the end of the Cure Period by giving written notice to the Company. If such action (or inaction) is corrected before the end of the Cure Period, then the Participant shall not be entitled to terminate his or her Employment for Good Reason as a result of such action (or inaction).

"Non-Section 409A Change in Control" means a Change in Control that is not a Section 409A Change in Control.

"Performance Goals" means the standards established by the Committee to determine in whole or in part whether the units of Common Stock under the RSU Award shall vest, which are specified in a separate document provided with this Award Agreement and made a part hereof for all purposes.

"Retirement" means a Separation from Service for any reason other than by the Company for Cause or due to death or Disability, (a) on or after the attainment of age 55 and with a sum of age and years of Employment of 65 or greater or (b) with at least five years of Employment in the role of Chief Executive Officer of the Company; *provided, however,* that a Separation from Service will not qualify as a "Retirement" unless the following conditions are satisfied:

(a) the Participant provides to the Company a comprehensive transition plan for the Participant's role and responsibilities and such plan is approved and accepted by the Company in its sole discretion;

(b) the Participant provides the Company at least three months' written notice of the Participant's Retirement or, if the Participant is a Section 16 Officer, reasonable advance written notice (as determined by the Committee) of the Participant's Retirement to the Chief Human Resources Officer; and

(c) If the Participant is a Section 16 Officer, the Committee approves, in its sole discretion, the Participant's Retirement under this Award Agreement prior to the Participant's Separation from Service.

"Sale of a Subsidiary" means, with respect to the Subsidiary for which the Participant is performing services at the time of the applicable event, the occurrence of any of the following events:

(a) A change in the ownership of such Subsidiary, as determined in accordance with Treasury Regulation § 1.409A-3(i)(5)(v) or

(b) A change in the ownership of a substantial portion of such Subsidiary's assets, as determined in accordance with Treasury Regulation § 1.409A-3(i)(5)(vii).

If the Subsidiary is not a corporation, the above referenced Treasury Regulations may be applied by analogy in accordance with guidance issued under Section 409A.

"Section 16 Officer" means a Participant who is an "officer" within the meaning of Section 16 of the Exchange Act as of the date notice of the Participant's Retirement is provided to the Chief Human Resources Officers.

"Section 409A" means Code Section 409A and the Treasury regulations and guidance issued thereunder.

"Section 409A Change in Control" means a Change in Control that satisfies the requirements of a change in control for purposes of Code Section 409A(a)(2)(A)(v) and the Treasury regulations and guidance issued thereunder.

"Separation from Service" means a separation from service with the Company or any of its Subsidiaries within the meaning of Treasury Regulation § 1.409A-1(h) (or any successor regulation).

"Termination Date" means the date of the Participant's Separation from Service.

"Vesting Date" means one or more vesting dates as specified in Section 3.

2. Establishment of RSU Award Account. The grant of units of Common Stock of the Company pursuant to this Award Agreement shall be implemented by a credit to a bookkeeping account maintained by the Company evidencing the accrual in favor of the Participant of the unfunded and unsecured right to receive a corresponding number of shares of Common Stock, which right shall be subject to the terms, conditions and restrictions set forth in the Plan and to the further terms, conditions and restrictions set forth in this Award Agreement. Except as otherwise provided in Section 12 of this Award Agreement, the units of Common Stock credited to the Participant's bookkeeping account may not be sold, assigned, transferred, pledged or otherwise encumbered until the Participant has been registered as the holder of shares of Common Stock on the records of the Company, as provided in Sections 4, 5, 6, or 7 of this Award Agreement.

3. Vesting of RSU Award. Unless earlier vested or forfeited pursuant to this Section 3 or Section 4 or 5 below, the Participant's right to receive shares of Common Stock under this Award Agreement, if any, shall vest with respect to the number of units and on the Vesting Date(s) as shown in the following schedule, conditioned upon achievement of the applicable Performance Goals:

<vesting_schedule>

No later than 60 days after each Vesting Date, the Committee shall determine the extent to which the applicable Performance Goals have been achieved. Upon completing its determination of the level at which the Performance Goals have been achieved, the Committee shall notify the Participant, in the form and manner as determined by the Committee, of the number of shares of Common Stock (if any) under this Award Agreement that will be issued to the Participant pursuant to Section 6. Except as provided in Sections 4 and 5 below, the Participant must be in continuous Employment during the period beginning on the Award Date and ending on the Vesting Date(s) in order for the units (as indicated above) of the RSU Award to vest on such Vesting Date(s); otherwise, all unvested units shall be forfeited as of the Participant's Termination Date.

4. Effect of Separation from Service; Timing of Distribution.

(a) Death or Disability. Notwithstanding Section 3 above, if the Participant's Termination Date occurs prior to (i) the final Vesting Date and (ii) the occurrence of a vesting event described in Section 5(b), 5(c), or 5(d) (in connection with a Change in Control or a Sale of a Subsidiary), and is due to the Participant's death or Separation from Service due to Disability, then, without regard to the Performance Goals, the Participant shall vest in the right to receive the total number of unvested units of Common Stock subject to this Award Agreement.

(b) Retirement. Notwithstanding Section 3 above, if the Participant's Termination Date occurs prior to (x) the final Vesting Date and (y) the occurrence of a vesting event described in Section 5(b), 5(c), or 5(d) (in connection with a Change in Control or a Sale of a Subsidiary) and is due to the Participant's Retirement, then the Participant shall vest in the right to receive the total number, if any, of unvested units of Common Stock subject to this Award Agreement based upon the Committee's determination of the achievement of the applicable Performance Goals as provided in Section 3, provided, however, that if the Participant's Retirement occurs before the January 1 immediately following the Award Date, the number of shares such Participant shall receive shall be pro-rated by multiplying (A) the total number of units of Common Stock covered by this RSU Award based upon the Committee's determination of the achievement of the Performance Goals as provided in Section 3 by (B) a fraction, the numerator of which is the number of days that have elapsed from the Award Date to the Participant's Termination Date and the denominator of which is the total number of days from the Award Date until the final Vesting Date, and subtracting any units that vested prior to the Termination Date.

If the Participant is a Section 16 Officer, benefits under this Section 5(b)(iii) shall be subject to the approval of the Committee, whose approval must occur prior to the Participant's Termination Date and is at the sole discretion of the Committee.

(c) Timing of Distribution.

(i) *Death or Disability.* If the Participant is entitled to a benefit pursuant to Section 4(a) hereof due to the Participant's death or Separation from Service due to Disability, then the number of shares of Common Stock determined in accordance with the applicable provision of this Section 4 shall be distributed not later than the 70th day after the Participant's Termination Date except as otherwise provided in Section 7.

(ii) *Retirement.* If the Participant is entitled to a benefit pursuant to Section 4(b) hereof due to the Participant's Retirement, then the number of shares of Common Stock determined in accordance with Section 4(b), as applicable, shall be distributed on or within 70 days after the Vesting Date(s) upon which such units would be paid under Section 3 hereof assuming continuous Employment by the Participant as of such Vesting Date(s).

(d) Dividend Equivalents. Upon the date of distribution of shares of Common Stock under this Section 4, the Participant shall also be entitled to receive Dividend Equivalents for the period from the Award Date to the date such vested shares of Common Stock are distributed to the Participant (in accordance with the requirements of Section 409A, to the extent applicable).

5. Change in Control.

(a) Assumption or Substitution. In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror"), may, without the Participant's consent, either assume or continue the Company's rights and obligations under this Award Agreement or provide a substantially equivalent award in substitution for the units subject to this RSU Award.

(b) Vesting Upon a Change in Control. Notwithstanding any provision of this Award Agreement to the contrary and without regard to the Performance Goals, if (i) there is a Change in Control and the Change in Control Closing Date occurs prior to the final Vesting Date and prior to the Participant's Separation from Service (other than due to Retirement) and (ii) the Acquiror does not assume or continue this RSU Award or provide a substantially equivalent award in substitution for this RSU Award pursuant to Section 5(a), then, upon the Change in Control Closing Date, the Participant's right to receive the unvested units of Common Stock subject to this Award Agreement shall be fully vested. Notwithstanding the foregoing, in the event the Change in Control occurs after the Participant has had a Separation from Service due to Retirement and such Retirement occurred before the January 1 immediately following the Award Date, the number of shares of Common Stock such Participant shall receive under this Section 5(b) shall be pro-rated based on the number of days that elapsed from the Award Date to the Participant's Termination Date over the total number of days from the Award Date until the final Vesting Date and reduced by the number of any shares received under Section 4(b).

(c) Vesting Upon a Covered Termination. Notwithstanding any provision of this Award Agreement to the contrary and without regard to the Performance Goals, if the Participant experiences a Covered Termination prior to the final Vesting Date, then, upon the date of the Covered Termination, the Participant's right to receive any unvested units of Common Stock subject to this Award Agreement shall be fully vested.

(d) Vesting Upon the Sale of a Subsidiary. Notwithstanding any provision of this Award Agreement to the contrary and without regard to the Performance Goals, if (i) there is a Sale of a Subsidiary with respect to the Participant prior to the final Vesting Date and (ii) the Participant's employment with the Company and all Subsidiaries (other than any entity that ceases to be a Subsidiary as a result of the Sale of a Subsidiary) ceases upon and in connection with such Sale of a Subsidiary, then upon such Sale of a Subsidiary, the Participant shall vest in the right to receive a number of the shares of Common Stock (rounded up to the nearest whole share) with respect to the unvested portion of this RSU Award determined by multiplying (x) the total number of units of Common Stock covered by this RSU Award by (y) a fraction, the numerator of which is the number of days that have elapsed from the Award Date to the date the Sale of a Subsidiary is consummated and the denominator of which is the total number of days from the Award Date until the final Vesting Date, and subtracting any units that vested prior to the Sale of the Subsidiary. The Participant's right to receive any additional shares pursuant to this Award Agreement shall be forfeited at such time.

(e) Distributions Upon a Change in Control or Sale of a Subsidiary. If the Participant is entitled to a benefit pursuant to Section 5(b), 5(c), or 5(d) hereof, then this RSU Award shall be settled by one or more distributions to the Participant of:

(i) The number of units of Common Stock subject to this Award Agreement not previously vested or forfeited pursuant to Sections 3 or 4 above (or such pro-rated amount as set forth in Section 5(b) or 5(d), if applicable), *plus*

(ii) Dividend Equivalents on such units of Common Stock in the form of shares of Common Stock (rounded up to the nearest whole share) for the period commencing on the Award Date and ending on the date immediately preceding the date of the distribution.

In lieu of the foregoing distribution in shares, the Committee, in its sole discretion, may direct that such distribution be made to the Participant in one or more cash payments equal to:

(x) The product of (A) the Fair Market Value per share of Common Stock on the date immediately preceding the date of the distribution and (B) the number of units of Common Stock subject to this Award Agreement not previously vested or forfeited pursuant to Sections 3 or 4 above (or such pro-rated amount as set forth in Section 5(b) or 5(d), if applicable), *plus*

(y) Dividend Equivalents on such units of Common Stock for the period commencing on the Award Date and ending on the date immediately preceding the date of the distribution.

Such distribution under this Section 5, whether in the form of shares of Common Stock or, if directed by the Committee, in cash, shall satisfy the rights of the Participant and the obligations of the Company under this Award Agreement in full.

(f) Timing of Distribution.

(i) *No Assumption or Substitution.* If the Participant is entitled to a benefit pursuant to Section 5(b), distributions shall be made in accordance with Section 5(e) on the Change in Control Payment Date.

(ii) *Covered Termination.* If the Participant is entitled to a benefit pursuant to Section 5(c) on account of a Covered Termination, distributions shall be made in accordance with Section 5(e) not later than the 70th day after the Participant's Termination Date except as otherwise provided in Section 7.

(iii) *Sale of a Subsidiary.* If the Participant is entitled to a benefit pursuant to Section 5(d), distributions shall be made in accordance with Section 5(e) not later than the 70th day after the date the Sale of a Subsidiary is consummated.

6. Payment of RSU Award Under Section 3. Upon the vesting of the Participant's right to receive a number of the shares of Common Stock pursuant to Section 3 under this Award Agreement, such shares of Common Stock will be distributed not later than the 70th day after the applicable Vesting Date. Moreover, upon the date of distribution of shares of Common Stock, the Participant shall also be entitled to receive Dividend Equivalents for the period commencing on the Award Date and ending on the date such vested shares of Common Stock are distributed to the Participant (in accordance with the requirements of Section 409A, to the extent applicable).

7. Delay of Distribution to Certain Participants. With respect to any benefits payable hereunder upon the Participant's Separation from Service (other than a Separation from Service due to the Participant's death), if as of the Participant's Termination Date, the Participant is a "specified employee" (within the meaning of Section 409A(a)(2)(B)), then such benefits shall not be distributed until the date that is the earlier of (a) the second business day following the end of the six-month period commencing on the Participant's Termination Date or (b) the Participant's date of death, if death occurs during such six-month period.

8. Confidentiality. The Participant agrees that the terms of this Award Agreement are confidential and that any disclosure to anyone for any purpose whatsoever (save and except disclosure to financial institutions as part of a financial statement, financial, tax and legal advisors, or as required by law) by the Participant or his or her agents, representatives, heirs, children, spouse, employees or spokespersons shall be a breach of this Award Agreement and the Company may elect to revoke the grant made hereunder, seek damages, plus interest and reasonable attorneys' fees, and take any other lawful actions to enforce this Award Agreement.

9. Participant Obligations.

(a) Confidentiality. The Participant acknowledges that in the course of his or her employment with the Company, the Company agrees to provide to the Participant

Confidential Information regarding the Company and the Company's business and has previously provided the Participant other such Confidential Information. In return for this and other consideration, provided under this Award Agreement, the Participant agrees that he or she will not, while employed by the Company and thereafter, disclose or make available to any other person or entity, or use for his own personal gain, any Confidential Information, except for such disclosures as required in the performance of his or her duties hereunder or as may otherwise be required by law or legal process (in which case the Participant shall notify the Company of such legal or judicial proceeding by a non-governmental party as soon as practicable following his receipt of notice of such a proceeding, and permit the Company to seek to protect its interests and information). Nothing in this Award Agreement, however, limits or precludes Participant from making a good faith voluntary report, charge, complaint, or claim to or providing truthful testimony and documents as required by law or under oath pursuant to a subpoena, court order, or request by the Equal Employment Opportunity Commission, the National Labor Relations Board, the Occupational Safety and Health Administration, the Securities and Exchange Commission or any other federal, state, or local government agency or commission ("Government Agencies"). Participant further understands that this Award Agreement does not limit Participant's ability to communicate with any Government Agencies or otherwise participate in any investigation or proceeding that may be conducted by any Government Agency, including providing documents or other information to the Government Agency, without notice to the Company. For purposes of this Award Agreement, "**Confidential Information**" shall mean any and all information, data and knowledge that has been created, discovered, developed or otherwise become known to the Company or any of its affiliates or ventures or in which property rights have been assigned or otherwise conveyed to the Company or any of its affiliates or ventures, which information, data or knowledge has commercial value in the business in which the Company is engaged, except such information, data or knowledge as is or becomes known to the public without violation of the terms of this Award Agreement. By way of illustration, but not limitation, Confidential Information includes business trade secrets, secrets concerning the Company's plans and strategies, nonpublic information concerning material market opportunities, technical trade secrets, processes, formulas, know-how, improvements, discoveries, developments, designs, inventions, techniques, marketing plans, manuals, records of research, reports, memoranda, computer software, strategies, forecasts, new products, unpublished financial information, projections, licenses, prices, costs, and employee, customer and supplier lists or parts thereof.

The Participant acknowledges notice that under the federal Defend Trade Secrets Act (DTSA), no individual may be held criminally or civilly liable under federal or state trade secret law for a trade secret disclosure that complies with 18 U.S.C. §1833(b) such as a disclosure (i) made in confidence to a federal, state, or local government official, either directly or indirectly, or to an attorney and made solely for the purpose of reporting or investigating a suspected violation of law or (ii) made in a complaint or other document filed in a lawsuit or other adjudicatory proceeding, if such filing is made under seal. Also, under the DTSA, an individual pursuing a legal claim for retaliation by an employer for reporting a suspected violation of the law may disclose a trade secret to his/her attorney and use it in information in the court or adjudicatory proceeding if the individual files any document containing the trade secret under seal and does not disclose the trade secret except to an order of the court or adjudicator.

(b) Return of Property. The Participant agrees that at the time of his or her Separation from Service, he or she will deliver to the Company (and will not keep in his or her possession, recreate or deliver to anyone else) all Confidential Information as well as all other devices, records, data, notes, reports, proposals, lists, correspondence, specifications, drawings, blueprints, sketches, materials, equipment, customer or client lists or information, or any other documents or property (including all reproductions of the aforementioned items) belonging to the Company or any of its affiliates or ventures, regardless of whether such items were prepared by the Participant.

(c) Non-Solicitation and Non-Competition.

(i) *Non-Solicitation.* For consideration provided under this Award Agreement, including, but not limited to the Company's agreement to provide the Participant with Confidential Information (as defined in Section 9(a)) regarding the Company and the Company's business, the Participant agrees that, while employed by the Company and for one year following his or her Separation from Service, he or she shall not, without the prior written consent of the Company, directly or indirectly, (i) hire or induce, entice or solicit (or attempt to induce, entice or solicit) any employee of the Company or any of its affiliates or ventures to leave the employment of the Company or any of its affiliates or ventures or (ii) solicit or attempt to solicit the business of any customer or acquisition prospect of the Company or any of its affiliates or ventures with whom the Participant had any actual contact while employed at the Company.

(ii) *Non-Competition.* For consideration provided under this Award Agreement, including, but not limited to the Company's agreement to provide the Participant with Confidential Information regarding the Company and the Company's business, the Participant agrees that while employed by the Company and for one year following a Separation from Service he or she will not, without the prior written consent of the Company, acting alone or in conjunction with others, either directly or indirectly, engage in any business that is in competition with the Company or accept employment with or render services to such a business as an officer, agent, employee, independent contractor or consultant, or otherwise engage in activities that are in competition with the Company.

(iii) *Restricted Area.* The restrictions contained in this Section 9(c) are limited to a 50-mile radius around any geographical area in which the Company engages (or has definite plans to engage) in operations or the marketing of its products or services at the time of the Participant's Separation from Service.

(iv) *Minnesota Participants.* If the Participant primarily resides and works for the Company in Minnesota when last employed with the Company or any of its affiliates, the post-employment non-competition covenant set forth in Section 9(c)(ii) above shall not apply to the Participant.

(d) Restrictions Reasonable. The Participant acknowledges that the restrictive covenants under this Section 9, for which the Participant received valuable consideration from the Company as provided in this Award Agreement, including, but not limited to the

Company's agreement to provide the Participant with Confidential Information regarding the Company and the Company's business are ancillary to otherwise enforceable provisions of this Award Agreement that the consideration provided by the Company gives rise to the Company's interest in restraining the Participant from competing and that the restrictive covenants are designed to enforce the Participant's consideration or return promises under this Award Agreement. Additionally, the Participant acknowledges that these restrictive covenants contain limitations as to time, geographical area, and scope of activity to be restrained that are reasonable and do not impose a greater restraint than is necessary to protect the goodwill or other legitimate business interests of the Company, including, but not limited to, the Company's need to protect its Confidential Information.

(e) **Violations.** If the Participant violates any provision of this Section 9, the Participant shall not be entitled to receive any amounts that would otherwise be payable to the Participant with respect to this RSU Award, and such amounts shall be forfeited. If the Participant violates any provision of this Section 9 after amounts under this RSU Award have been paid or if the Company learns of the violation after amounts under this RSU Award have been paid, the Participant shall repay to the Company the Common Shares (or the equivalent value thereof determined as of the date of the Company's demand) or the cash received, as the case may be, within thirty (30) days of receiving a demand from the Company for the repayment of the award. Further, the Company shall be entitled to an award of attorneys' fees incurred with securing any relief hereunder and/or pursuant to a breach or threatened breach of this Section 9.

10. Notices. For purposes of this Award Agreement, notices to the Company shall be deemed to have been duly given upon receipt of written notice by the Corporate Secretary of CenterPoint Energy, Inc., 1111 Louisiana, Houston, Texas 77002, or to such other address as the Company may furnish to the Participant.

Notices to the Participant shall be deemed effectively delivered or given upon personal, electronic, or postal delivery of written notice to the Participant, the place of Employment of the Participant, the address on record for the Participant at the human resources department of the Company, or such other address as the Participant hereafter designates by written notice to the Company.

11. Shareholder Rights. The Participant shall have no rights of a shareholder with respect to the units of Common Stock subject to this Award Agreement, unless and until the Participant is registered as the holder of such shares of Common Stock.

12. Successors and Assigns. This Award Agreement shall bind and inure to the benefit of and be enforceable by the Participant, the Company and their respective permitted successors and assigns except as expressly prohibited herein and in the Plan. Notwithstanding anything herein or in the Plan to the contrary, the units of Common Stock are transferable by the Participant to Immediate Family Members, Immediate Family Member trusts, and Immediate Family Member partnerships pursuant to Section 13 of the Plan.

13. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the

Company or any Subsidiary, or any successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

14. Waiver. Failure of either party to demand strict compliance with any of the terms or conditions hereof shall not be deemed a waiver of such term or condition, nor shall any waiver by either party of any right hereunder at any one time or more times be deemed a waiver of such right at any other time or times. No term or condition hereof shall be deemed to have been waived except by written instrument.

15. Compliance with Section 409A. It is the intent of the Company and the Participant that the provisions of the Plan and this Award Agreement comply with Section 409A and will be interpreted and administered consistent therewith. Accordingly, (a) no adjustment to the RSU Award pursuant to Section 14 of the Plan and (b) no substitutions of the benefits under this Award Agreement, in each case, shall be made in a manner that results in noncompliance with the requirements of Section 409A, to the extent applicable.

16. Modification of Award Agreement. Any modification of this Award Agreement is subject to Section 15 hereof and shall be binding only if evidenced in writing and signed by an authorized representative of the Company.

17. Severability. If any provision of this Award Agreement is, becomes or is deemed to be invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions of the Award Agreement shall not be affected thereby.

SIGNIFICANT SUBSIDIARIES OF CENTERPOINT ENERGY, INC.

The following subsidiaries are deemed “significant subsidiaries” pursuant to Item 601(b) (21) of Regulation S-K:

Utility Holding, LLC, a Delaware limited liability company and a direct wholly-owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Houston Electric, LLC, a Texas limited liability company and an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Resources Corp., a Delaware corporation and an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Investment Management, Inc., a Delaware corporation and an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.

Vectren Affiliated Utilities, Inc. an Indiana corporation and an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.

Vectren LLC, an Indiana limited liability company and a wholly-owned subsidiary of Vectren Affiliated Utilities, Inc..

Vectren Utility Holdings LLC, an Indiana limited liability company and a wholly-owned subsidiary of Vectren LLC

Southern Indiana Gas and Electric Company, an Indiana corporation and a wholly-owned subsidiary of Vectren Utility Holdings LLC (doing business as Vectren Energy Delivery of Indiana, Inc.)

Indiana Gas Company, Inc., an Indiana corporation and a wholly-owned subsidiary of CenterPoint Energy Resources Corp.

Vectren Energy Delivery of Ohio, LLC, an Ohio limited liability company and a wholly-owned subsidiary of CenterPoint Energy Resources Corp.

(1) Pursuant to Item 601(b) (21) of Regulation S-K, registrant has omitted the names of subsidiaries, which considered in the aggregate as a single subsidiary, would not constitute a “significant subsidiary” (as defined under Rule 1-02(w) of Regulation S-X) as of December 31, 2025.

SIGNIFICANT SUBSIDIARIES OF CENTERPOINT ENERGY RESOURCES CORP.

The following subsidiaries are deemed “significant subsidiaries” pursuant to Item 601(b) (21) of Regulation S-K:

Indiana Gas Company, Inc., an Indiana corporation and a wholly-owned subsidiary of CenterPoint Energy Resources Corp.

Vectren Energy Delivery of Ohio, LLC, an Ohio limited liability company and a wholly-owned subsidiary of CenterPoint Energy Resources Corp.

(1) Pursuant to Item 601(b) (21) of Regulation S-K, registrant has omitted the names of subsidiaries, which considered in the aggregate as a single subsidiary, would not constitute a “significant subsidiary” (as defined under Rule 1-02(w) of Regulation S-X) as of December 31, 2025.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-272025, 333-289261, and 333-238844 on Form S-3; Registration Statement Nos. 333-286674, 333-264489, 333-238800, 333-203201, 333-179310, 333-173660, 333-149757, 333-101202, 333-115976, 333-159586, and 333-105773 on Form S-8; Post-Effective Amendment No. 1 to Registration Statement Nos. 333-32413-99, 333-49333-99, 333-38188-99, 333-60260-99, and 333-98271-99 on Form S-8; Post-Effective Amendment No. 5 to Registration Statement No. 333-11329-99 on Form S-8; and Post-Effective Amendment No. 2 to Registration Statement No. 333-159586 of our reports dated February 19, 2026, relating to the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting appearing in this Annual Report on Form 10-K of CenterPoint Energy, Inc. for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Houston, Texas
February 19, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-272025-02 on Form S-3 of our report dated February 19, 2026, relating to the consolidated financial statements of CenterPoint Energy Houston Electric, LLC and subsidiaries appearing in this Annual Report on Form 10-K of CenterPoint Energy Houston Electric, LLC for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Houston, Texas
February 19, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-272025-01 on Form S-3 of our report dated February 19, 2026, relating to the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Houston, Texas
February 19, 2026

CERTIFICATIONS

I, Jason P. Wells, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ JASON P. WELLS

Jason P. Wells

President and Chief Executive Officer

CERTIFICATIONS

I, Jesus Soto, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Houston Electric, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ JESUS SOTO, JR.

Jesus Soto, Jr.

President and Chief Executive Officer

CERTIFICATIONS

I, Jesus Soto, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ JESUS SOTO, JR.

Jesus Soto, Jr.

President and Chief Executive Officer

CERTIFICATIONS

I, Christopher A. Foster, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster

Executive Vice President and Chief Financial Officer

CERTIFICATIONS

I, Christopher A. Foster, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Houston Electric, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster
Executive Vice President and Chief Financial Officer

CERTIFICATIONS

I, Christopher A. Foster, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2026

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster

Executive Vice President and Chief Financial Officer

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jason P. Wells, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JASON P. WELLS

Jason P. Wells
President and Chief Executive Officer
February 19, 2026

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Houston Electric, LLC (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jesus Soto, Jr., Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JESUS SOTO, JR.

Jesus Soto, Jr.
President and Chief Executive Officer
February 19, 2026

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jesus Soto, Jr., Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JESUS SOTO, JR.

Jesus Soto, Jr.
President and Chief Executive Officer
February 19, 2026

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Christopher A. Foster, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster
Executive Vice President and Chief Financial Officer
February 19, 2026

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Houston Electric, LLC (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Christopher A. Foster, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster
Executive Vice President and Chief Financial Officer
February 19, 2026

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the "Company") on Form 10-K for the year ended December 31, 2025 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Christopher A. Foster, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ CHRISTOPHER A. FOSTER

Christopher A. Foster
Executive Vice President and Chief Financial Officer
February 19, 2026

Executive Officer Recovery Policy
(As amended and restated July 17, 2025)

1. **Purpose.** The purpose of this Policy is to describe the circumstances under which Executive Officers will be required to repay or return Erroneously Awarded Compensation to the Company Group. This Policy shall not supersede any other recoupment or similar policy of the Company Group, and any such other policy shall remain in full force and effect until otherwise terminated or superseded; however, to the extent any policy or procedure of the Company Group conflicts with this Policy, this Policy shall prevail.

2. **Administration.** This Policy shall be administered by the Committee. Any determinations made by the Committee shall be final and binding on all affected individuals.

3. **Definitions.** For purposes of this Policy, the following capitalized terms shall have the meanings set forth below.

(a) *“Accounting Restatement”* shall mean an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that (i) is material to the previously issued financial statements (a “Big R” restatement) or (ii) is not material to previously issued financial statements but would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a “little r” restatement).

For purposes of this policy, an Accounting Restatement shall not be deemed to occur in the event of a revision of the Company’s financial statements due to an out-of-period adjustment (*i.e.*, when the error is immaterial to the previously issued financial statements and the correction of the error is also immaterial to the current period) or a retrospective (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Company’s internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; or (v) revision for stock splits, reverse stock splits, stock dividends, or other changes in capital structure.

(b) *“Board”* shall mean the Board of Directors of the Company.

(c) *“Committee”* shall mean the Human Capital and Compensation Committee of the Board or any successor committee thereof.

(d) *“Company”* shall mean CenterPoint Energy, Inc.

(e) *“Company Group”* shall mean the Company, together with each of its direct and indirect subsidiaries.

(f) *“Covered Incentive Compensation”* shall mean all Incentive-based Compensation Received by an Executive Officer (i) on or after the Effective Date, (ii) after beginning service as an Executive Officer, (iii) who served as an Executive Officer at any time during the performance period for that Incentive-based Compensation (whether or not such Executive Officer is serving at the time the Erroneously Awarded Compensation is required to be repaid to the Company Group), (iv) while the Company has a class of securities listed on a national securities exchange or a national securities association, and (v) during the applicable Recovery Period.

(g) “*Effective Date*” shall mean October 2, 2023.

(h) “*Erroneously Awarded Compensation*” shall mean, with respect to each Executive Officer in connection with an Accounting Restatement, the amount of Covered Incentive Compensation that exceeds the amount of Incentive-based Compensation that otherwise would have been Received had it been determined based on the restated amounts, computed without regard to any taxes paid.

(i) “*Executive Officer*” shall mean each individual who is or was designated as an “officer” of the Company within the meaning of Section 16 of the Securities Exchange Act of 1934, as amended, in accordance with 17 C.F.R. 240.16a-1(f). For the avoidance of doubt, the identification of an executive officer for purposes of this Policy shall include at a minimum executive officers identified pursuant to 17 C.F.R. 229.401(b).

(j) “*Financial Reporting Measures*” shall mean measures that are determined and presented in accordance with the accounting principles used in preparing the Company’s financial statements, and all other measures that are derived wholly or in part from such measures. Stock price and total shareholder return shall be considered Financial Reporting Measures for purposes of this Policy. For the avoidance of doubt, a Financial Reporting Measure need not be presented in the Company’s financial statements or included in a filing with the SEC.

(k) “*Incentive-based Compensation*” shall mean any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

(l) “*NYSE*” shall mean the New York Stock Exchange.

(m) “*Policy*” shall mean this Executive Officer Recovery Policy, as the same may be amended and/or restated from time to time.

(n) “*Received*” shall mean, with respect to any Incentive-based Compensation, actual or deemed receipt, and Incentive-based Compensation shall be deemed Received in the Company’s fiscal period during which the Financial Reporting Measure specified in the Incentive-based Compensation award is attained, even if payment or grant of the Incentive-based Compensation occurs after the end of that period.

(o) “*Recovery Period*” shall mean, with respect to any Accounting Restatement, the three completed fiscal years of the Company immediately preceding the Restatement Date and any transition period (that results from a change in the Company’s fiscal year) of less than nine months within or immediately following those three completed fiscal years.

(p) “*Restatement Date*” shall mean the earlier to occur of (i) the date the Board, a committee of the Board, or the officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement, or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.

(q) “*SEC*” shall mean the U.S. Securities and Exchange Commission.

4. **Repayment of Erroneously Awarded Compensation.**

(a) In the event a Restatement Date occurs, the Committee shall reasonably promptly

recover any Erroneously Awarded Compensation. The Committee shall promptly determine the amount of any Erroneously Awarded Compensation for each Executive Officer in connection with the Accounting Restatement and provide each Executive Officer with a written notice containing the amount of Erroneously Awarded Compensation and a demand for repayment or return, as applicable. For Incentive-based Compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the applicable Accounting Restatement, the amount shall be determined by the Committee based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive-based Compensation was Received, and the Company shall maintain documentation of such determination of that reasonable estimate and provide such documentation to NYSE.

(b) The Committee shall have discretion to determine the appropriate means of recovery of Erroneously Awarded Compensation based on all applicable facts and circumstances and taking into account the time value of money and additional costs incident to recovery efforts. To the extent that the Committee determines that any method of recovery other than prompt repayment by the Executive Officer in a lump sum in cash or property is appropriate, a repayment agreement with the Executive Officer, in a form reasonably acceptable to the Committee, shall be required to implement such method. In no event may the Company Group accept an amount that is less than the amount of Erroneously Awarded Compensation in satisfaction of an Executive Officer's obligations hereunder, except that to the extent the Executive Officer has already reimbursed the Company Group for any Erroneously Awarded Compensation Received under any duplicative recovery obligations, the Committee may determine that it is appropriate for such amount already reimbursed by the Executive Officer to be credited to the required recovery under this Policy. Notwithstanding anything to the contrary herein, the Committee has no obligation under this Policy to seek recoupment of amounts that are not Incentive-based Compensation. Such exempt compensation includes, without limitation, base salary; time-vesting awards; compensation awarded on the basis of the achievement of metrics that are not Financial Reporting Measures; and compensation awarded solely at the discretion of the Committee, the Board, or a group composed entirely of independent members of the Board, provided, in each case, that such amounts are in no way contingent on, and were not in any way granted on the basis of, the achievement of any Financial Reporting Measure.

(c) To the extent that an Executive Officer fails to repay all Erroneously Awarded Compensation to the Company Group when due, the Company shall, or shall cause one or more other members of the Company Group to, take all actions reasonable and appropriate, as determined by the Committee, to recover such Erroneously Awarded Compensation from the applicable Executive Officer. The applicable Executive Officer shall be required to reimburse the Company Group for any and all expenses reasonably incurred (including legal fees) by the Company Group in recovering such Erroneously Awarded Compensation in accordance with the immediately preceding sentence.

(d) Notwithstanding anything herein to the contrary, the Company shall not be required to take the actions contemplated by Sections 4(a), (b), and (c) above if either of the following conditions are met and the Committee determines that recovery would be impracticable:

(i) The direct expenses paid to a third party to assist in enforcing the Policy would exceed the amount to be recovered, but only if the Company has first made a reasonable attempt to recover the applicable Erroneously Awarded Compensation, documented such attempts, and provided such documentation to the NYSE; or

(ii) Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company Group, to fail to

meet the requirements of Section 401(a)(13) or Section 411(a) of the Internal Revenue Code of 1986, as amended, and regulations thereunder.

5. **Reporting and Disclosure.** The Company shall file all disclosures with respect to this Policy in accordance with the requirements of federal securities laws, including disclosures required by the applicable SEC filings and rules.

6. **Indemnification Prohibition.** No member of the Company Group shall be permitted to indemnify any Executive Officer against (a) the loss of any Erroneously Awarded Compensation that is repaid, returned or recovered pursuant to the terms of this Policy or (b) any claims relating to the Company Group's enforcement of its rights under this Policy. Further, no member of the Company Group shall enter into any agreement that exempts any Incentive-based Compensation from the application of this Policy or that waives the Company Group's right to recovery of any Erroneously Awarded Compensation, and this Policy shall supersede any such agreement (whether entered into before, on, or after the Effective Date).

7. **Interpretation.** The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. Notwithstanding the foregoing, this Policy is intended to satisfy the requirements of Section 10D of the Securities Exchange Act of 1934 and any applicable rules or standards adopted by the SEC or NYSE and will be interpreted and administered consistent therewith.

8. **Effective Date.** This Policy was first effective as of the Effective Date.

9. **Amendment; Termination.** The Committee may amend this Policy from time to time in its discretion and shall amend this Policy as it deems necessary, including as and when it determines that it is legally required by any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed. The Committee may terminate this Policy at any time. Notwithstanding anything in this Section 9 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Company contemporaneously with such amendment or termination) cause the Company to violate any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed.

10. **Other Recoupment Rights; No Additional Payments.** The Committee intends that this Policy will be applied to the fullest extent of the law. The Committee may require that any employment agreement, equity award agreement, or any other agreement entered into on or after the Effective Date shall, as a condition to the grant of any benefit thereunder, require an Executive Officer to agree to abide by the terms of this Policy. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company Group under applicable law, regulation or rule or pursuant to the terms of any similar policy of the Company Group or any provision in any employment agreement, equity award agreement, or other agreement or arrangement.

11. **Successors.** This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives.

CenterPoint Energy Houston Electric, LLC
Executive Officer Recovery Policy
(As amended and restated July 17, 2025)

1. **Purpose.** The purpose of this Policy is to describe the circumstances under which Executive Officers will be required to repay or return Erroneously Awarded Compensation to the Company Group. This Policy shall not supersede any other recoupment or similar policy of the Company Group, and any such other policy shall remain in full force and effect until otherwise terminated or superseded; however, to the extent any policy or procedure of the Company Group conflicts with this Policy, this Policy shall prevail.

2. **Administration.** This Policy shall be administered by the Committee. Any determinations made by the Committee shall be final and binding on all affected individuals.

3. **Definitions.** For purposes of this Policy, the following capitalized terms shall have the meanings set forth below.

(a) *“Accounting Restatement”* shall mean an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that (i) is material to the previously issued financial statements (a “Big R” restatement) or (ii) is not material to previously issued financial statements but would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a “little r” restatement).

For purposes of this policy, an Accounting Restatement shall not be deemed to occur in the event of a revision of the Company’s financial statements due to an out-of-period adjustment (*i.e.*, when the error is immaterial to the previously issued financial statements and the correction of the error is also immaterial to the current period) or a retrospective (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Company’s internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; or (v) revision for stock splits, reverse stock splits, stock dividends, or other changes in capital structure.

(b) *“Board”* shall mean the Board of Directors of CenterPoint Energy, Inc.

(c) *“Committee”* shall mean the Human Capital and Compensation Committee of the Board or any successor committee thereof.

(d) *“Company”* shall mean CenterPoint Energy Houston Electric, LLC.

(e) *“Company Group”* shall mean the Company, together with CenterPoint Energy, Inc. and each of their direct and indirect subsidiaries.

(f) *“Covered Incentive Compensation”* shall mean all Incentive-based Compensation Received by an Executive Officer (i) on or after the Effective Date, (ii) after beginning service as an Executive Officer, (iii) who served as an Executive Officer at any time during the performance period for that Incentive-based Compensation (whether or not such Executive Officer is serving at the time the Erroneously Awarded Compensation is required to be repaid to the Company Group), (iv) while the Company has a class of securities listed on a national securities exchange or a national securities association, and (v) during the applicable Recovery Period.

- (g) “*Effective Date*” shall mean October 2, 2023.
- (h) “*Erroneously Awarded Compensation*” shall mean, with respect to each Executive Officer in connection with an Accounting Restatement, the amount of Covered Incentive Compensation that exceeds the amount of Incentive-based Compensation that otherwise would have been Received had it been determined based on the restated amounts, computed without regard to any taxes paid.
- (i) “*Executive Officer*” shall mean each individual who is or was designated as an “officer” of the Company within the meaning of Section 16 of the Securities Exchange Act of 1934, as amended, in accordance with 17 C.F.R. 240.16a-1(f). For the avoidance of doubt, the identification of an executive officer for purposes of this Policy shall include at a minimum executive officers identified pursuant to 17 C.F.R. 229.401(b).
- (j) “*Financial Reporting Measures*” shall mean measures that are determined and presented in accordance with the accounting principles used in preparing the Company’s financial statements, and all other measures that are derived wholly or in part from such measures. Stock price and total shareholder return shall be considered Financial Reporting Measures for purposes of this Policy. For the avoidance of doubt, a Financial Reporting Measure need not be presented in the Company’s financial statements or included in a filing with the SEC.
- (k) “*Incentive-based Compensation*” shall mean any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.
- (l) “*Manager*” shall mean the manager, the managing board, or other governing body of the Company.
- (m) “*NYSE*” shall mean the New York Stock Exchange.
- (n) “*Policy*” shall mean this Executive Officer Recovery Policy, as the same may be amended and/or restated from time to time.
- (o) “*Received*” shall mean, with respect to any Incentive-based Compensation, actual or deemed receipt, and Incentive-based Compensation shall be deemed Received in the Company’s fiscal period during which the Financial Reporting Measure specified in the Incentive-based Compensation award is attained, even if payment or grant of the Incentive-based Compensation occurs after the end of that period.
- (p) “*Recovery Period*” shall mean, with respect to any Accounting Restatement, the three completed fiscal years of the Company immediately preceding the Restatement Date and any transition period (that results from a change in the Company’s fiscal year) of less than nine months within or immediately following those three completed fiscal years.
- (q) “*Restatement Date*” shall mean the earlier to occur of (i) the date the Manager, or the officers of the Company authorized to take such action if Manager action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement, or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.
- (r) “*SEC*” shall mean the U.S. Securities and Exchange Commission.

4. **Repayment of Erroneously Awarded Compensation.**

(a) In the event a Restatement Date occurs, the Committee shall reasonably promptly recover any Erroneously Awarded Compensation. The Committee shall promptly determine the amount of any Erroneously Awarded Compensation for each Executive Officer in connection with the Accounting Restatement and provide each Executive Officer with a written notice containing the amount of Erroneously Awarded Compensation and a demand for repayment or return, as applicable. For Incentive-based Compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the applicable Accounting Restatement, the amount shall be determined by the Committee based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive-based Compensation was Received, and the Company shall maintain documentation of such determination of that reasonable estimate and provide such documentation to NYSE.

(b) The Committee shall have discretion to determine the appropriate means of recovery of Erroneously Awarded Compensation based on all applicable facts and circumstances and taking into account the time value of money and additional costs incident to recovery efforts. To the extent that the Committee determines that any method of recovery other than prompt repayment by the Executive Officer in a lump sum in cash or property is appropriate, a repayment agreement with the Executive Officer, in a form reasonably acceptable to the Committee, shall be required to implement such method. In no event may the Company Group accept an amount that is less than the amount of Erroneously Awarded Compensation in satisfaction of an Executive Officer's obligations hereunder, except that to the extent the Executive Officer has already reimbursed the Company Group for any Erroneously Awarded Compensation Received under any duplicative recovery obligations, the Committee may determine that it is appropriate for such amount already reimbursed by the Executive Officer to be credited to the required recovery under this Policy. Notwithstanding anything to the contrary herein, the Committee has no obligation under this Policy to seek recoupment of amounts that are not Incentive-based Compensation. Such exempt compensation includes, without limitation, base salary; time-vesting awards; compensation awarded on the basis of the achievement of metrics that are not Financial Reporting Measures; and compensation awarded solely at the discretion of the Committee, the Board, or a group composed entirely of independent members of the Board, provided, in each case, that such amounts are in no way contingent on, and were not in any way granted on the basis of, the achievement of any Financial Reporting Measure.

(c) To the extent that an Executive Officer fails to repay all Erroneously Awarded Compensation to the Company Group when due, the Company shall, or shall cause one or more other members of the Company Group to, take all actions reasonable and appropriate, as determined by the Committee, to recover such Erroneously Awarded Compensation from the applicable Executive Officer. The applicable Executive Officer shall be required to reimburse the Company Group for any and all expenses reasonably incurred (including legal fees) by the Company Group in recovering such Erroneously Awarded Compensation in accordance with the immediately preceding sentence.

(d) Notwithstanding anything herein to the contrary, the Company shall not be required to take the actions contemplated by Sections 4(a), (b), and (c) above if either of the following conditions are met and the Committee determines that recovery would be impracticable:

(i) The direct expenses paid to a third party to assist in enforcing the Policy would exceed the amount to be recovered, but only if the Company has first made a reasonable attempt to recover the applicable Erroneously Awarded Compensation, documented such attempts, and provided such documentation to the NYSE; or

(ii) Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company Group, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Internal Revenue Code of 1986, as amended, and regulations thereunder.

5. **Reporting and Disclosure.** The Company shall file all disclosures with respect to this Policy in accordance with the requirements of federal securities laws, including disclosures required by the applicable SEC filings and rules.

6. **Indemnification Prohibition.** No member of the Company Group shall be permitted to indemnify any Executive Officer against (a) the loss of any Erroneously Awarded Compensation that is repaid, returned or recovered pursuant to the terms of this Policy or (b) any claims relating to the Company Group's enforcement of its rights under this Policy. Further, no member of the Company Group shall enter into any agreement that exempts any Incentive-based Compensation from the application of this Policy or that waives the Company Group's right to recovery of any Erroneously Awarded Compensation, and this Policy shall supersede any such agreement (whether entered into before, on, or after the Effective Date).

7. **Interpretation.** The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. Notwithstanding the foregoing, this Policy is intended to satisfy the requirements of Section 10D of the Securities Exchange Act of 1934 and any applicable rules or standards adopted by the SEC or NYSE and will be interpreted and administered consistent therewith.

8. **Effective Date.** This Policy was first effective as of the Effective Date.

9. **Amendment; Termination.** The Committee may amend this Policy from time to time in its discretion and shall amend this Policy as it deems necessary, including as and when it determines that it is legally required by any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed. The Committee may terminate this Policy at any time. Notwithstanding anything in this Section 9 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Company contemporaneously with such amendment or termination) cause the Company to violate any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed.

10. **Other Recoupment Rights; No Additional Payments.** The Committee intends that this Policy will be applied to the fullest extent of the law. The Committee may require that any employment agreement, equity award agreement, or any other agreement entered into on or after the Effective Date shall, as a condition to the grant of any benefit thereunder, require an Executive Officer to agree to abide by the terms of this Policy. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company Group under applicable law, regulation or rule or pursuant to the terms of any similar policy of the Company Group or any provision in any employment agreement, equity award agreement, or other agreement or arrangement.

11. **Successors.** This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives.

CenterPoint Energy Resources Corp.
Executive Officer Recovery Policy
(As amended and restated July 17, 2025)

1. **Purpose.** The purpose of this Policy is to describe the circumstances under which Executive Officers will be required to repay or return Erroneously Awarded Compensation to the Company Group. This Policy shall not supersede any other recoupment or similar policy of the Company Group, and any such other policy shall remain in full force and effect until otherwise terminated or superseded; however, to the extent any policy or procedure of the Company Group conflicts with this Policy, this Policy shall prevail.

2. **Administration.** This Policy shall be administered by the Committee. Any determinations made by the Committee shall be final and binding on all affected individuals.

3. **Definitions.** For purposes of this Policy, the following capitalized terms shall have the meanings set forth below.

(a) *“Accounting Restatement”* shall mean an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that (i) is material to the previously issued financial statements (a “Big R” restatement) or (ii) is not material to previously issued financial statements but would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a “little r” restatement).

For purposes of this policy, an Accounting Restatement shall not be deemed to occur in the event of a revision of the Company’s financial statements due to an out-of-period adjustment (*i.e.*, when the error is immaterial to the previously issued financial statements and the correction of the error is also immaterial to the current period) or a retrospective (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Company’s internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; or (v) revision for stock splits, reverse stock splits, stock dividends, or other changes in capital structure.

(b) *“Board”* shall mean the Board of Directors of the Company.

(c) *“CNP Board”* shall mean the Board of Directors of CenterPoint Energy, Inc.

(d) *“Committee”* shall mean the Human Capital and Compensation Committee of the CNP Board or any successor committee thereof.

(e) *“Company”* shall mean CenterPoint Energy Resources Corporation.

(f) *“Company Group”* shall mean the Company, together with CenterPoint Energy, Inc. and each of their direct and indirect subsidiaries.

(g) *“Covered Incentive Compensation”* shall mean all Incentive-based Compensation Received by an Executive Officer (i) on or after the Effective Date, (ii) after beginning service as an Executive Officer, (iii) who served as an Executive Officer at any time during the performance period for that Incentive-based Compensation (whether or not such Executive Officer is serving at the time the Erroneously Awarded Compensation is required to be repaid to the Company Group), (iv) while

the Company has a class of securities listed on a national securities exchange or a national securities association, and (v) during the applicable Recovery Period.

(h) “*Effective Date*” shall mean October 2, 2023.

(i) “*Erroneously Awarded Compensation*” shall mean, with respect to each Executive Officer in connection with an Accounting Restatement, the amount of Covered Incentive Compensation that exceeds the amount of Incentive-based Compensation that otherwise would have been Received had it been determined based on the restated amounts, computed without regard to any taxes paid.

(j) “*Executive Officer*” shall mean each individual who is or was designated as an “officer” of the Company within the meaning of Section 16 of the Securities Exchange Act of 1934, as amended, in accordance with 17 C.F.R. 240.16a-1(f). For the avoidance of doubt, the identification of an executive officer for purposes of this Policy shall include at a minimum executive officers identified pursuant to 17 C.F.R. 229.401(b).

(k) “*Financial Reporting Measures*” shall mean measures that are determined and presented in accordance with the accounting principles used in preparing the Company’s financial statements, and all other measures that are derived wholly or in part from such measures. Stock price and total shareholder return shall be considered Financial Reporting Measures for purposes of this Policy. For the avoidance of doubt, a Financial Reporting Measure need not be presented in the Company’s financial statements or included in a filing with the SEC.

(l) “*Incentive-based Compensation*” shall mean any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

(m) “*NYSE*” shall mean the New York Stock Exchange.

(n) “*Policy*” shall mean this Executive Officer Recovery Policy, as the same may be amended and/or restated from time to time.

(o) “*Received*” shall mean, with respect to any Incentive-based Compensation, actual or deemed receipt, and Incentive-based Compensation shall be deemed Received in the Company’s fiscal period during which the Financial Reporting Measure specified in the Incentive-based Compensation award is attained, even if payment or grant of the Incentive-based Compensation occurs after the end of that period.

(p) “*Recovery Period*” shall mean, with respect to any Accounting Restatement, the three completed fiscal years of the Company immediately preceding the Restatement Date and any transition period (that results from a change in the Company’s fiscal year) of less than nine months within or immediately following those three completed fiscal years.

(q) “*Restatement Date*” shall mean the earlier to occur of (i) the date the Board, a committee of the Board, or the officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement, or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.

(r) “*SEC*” shall mean the U.S. Securities and Exchange Commission.

4. **Repayment of Erroneously Awarded Compensation.**

(a) In the event a Restatement Date occurs, the Committee shall reasonably promptly recover any Erroneously Awarded Compensation. The Committee shall promptly determine the amount of any Erroneously Awarded Compensation for each Executive Officer in connection with the Accounting Restatement and provide each Executive Officer with a written notice containing the amount of Erroneously Awarded Compensation and a demand for repayment or return, as applicable. For Incentive-based Compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the applicable Accounting Restatement, the amount shall be determined by the Committee based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive-based Compensation was Received, and the Company shall maintain documentation of such determination of that reasonable estimate and provide such documentation to NYSE.

(b) The Committee shall have discretion to determine the appropriate means of recovery of Erroneously Awarded Compensation based on all applicable facts and circumstances and taking into account the time value of money and additional costs incident to recovery efforts. To the extent that the Committee determines that any method of recovery other than prompt repayment by the Executive Officer in a lump sum in cash or property is appropriate, a repayment agreement with the Executive Officer, in a form reasonably acceptable to the Committee, shall be required to implement such method. In no event may the Company Group accept an amount that is less than the amount of Erroneously Awarded Compensation in satisfaction of an Executive Officer's obligations hereunder, except that to the extent the Executive Officer has already reimbursed the Company Group for any Erroneously Awarded Compensation Received under any duplicative recovery obligations, the Committee may determine that it is appropriate for such amount already reimbursed by the Executive Officer to be credited to the required recovery under this Policy. Notwithstanding anything to the contrary herein, the Committee has no obligation under this Policy to seek recoupment of amounts that are not Incentive-based Compensation. Such exempt compensation includes, without limitation, base salary; time-vesting awards; compensation awarded on the basis of the achievement of metrics that are not Financial Reporting Measures; and compensation awarded solely at the discretion of the Committee, the CNP Board, or a group composed entirely of independent members of the CNP Board, provided, in each case, that such amounts are in no way contingent on, and were not in any way granted on the basis of, the achievement of any Financial Reporting Measure.

(c) To the extent that an Executive Officer fails to repay all Erroneously Awarded Compensation to the Company Group when due, the Company shall, or shall cause one or more other members of the Company Group to, take all actions reasonable and appropriate, as determined by the Committee, to recover such Erroneously Awarded Compensation from the applicable Executive Officer. The applicable Executive Officer shall be required to reimburse the Company Group for any and all expenses reasonably incurred (including legal fees) by the Company Group in recovering such Erroneously Awarded Compensation in accordance with the immediately preceding sentence.

(d) Notwithstanding anything herein to the contrary, the Company shall not be required to take the actions contemplated by Sections 4(a), (b), and (c) above if either of the following conditions are met and the Committee determines that recovery would be impracticable:

(i) The direct expenses paid to a third party to assist in enforcing the Policy would exceed the amount to be recovered, but only if the Company has first made a reasonable attempt to recover the applicable Erroneously Awarded Compensation, documented such attempts, and provided such documentation to the NYSE; or

(ii) Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company Group, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Internal Revenue Code of 1986, as amended, and regulations thereunder.

5. **Reporting and Disclosure.** The Company shall file all disclosures with respect to this Policy in accordance with the requirements of federal securities laws, including disclosures required by the applicable SEC filings and rules.

6. **Indemnification Prohibition.** No member of the Company Group shall be permitted to indemnify any Executive Officer against (a) the loss of any Erroneously Awarded Compensation that is repaid, returned or recovered pursuant to the terms of this Policy or (b) any claims relating to the Company Group's enforcement of its rights under this Policy. Further, no member of the Company Group shall enter into any agreement that exempts any Incentive-based Compensation from the application of this Policy or that waives the Company Group's right to recovery of any Erroneously Awarded Compensation, and this Policy shall supersede any such agreement (whether entered into before, on, or after the Effective Date).

7. **Interpretation.** The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. Notwithstanding the foregoing, this Policy is intended to satisfy the requirements of Section 10D of the Securities Exchange Act of 1934 and any applicable rules or standards adopted by the SEC or NYSE and will be interpreted and administered consistent therewith.

8. **Effective Date.** This Policy was first effective as of the Effective Date.

9. **Amendment; Termination.** The Committee may amend this Policy from time to time in its discretion and shall amend this Policy as it deems necessary, including as and when it determines that it is legally required by any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed. The Committee may terminate this Policy at any time. Notwithstanding anything in this Section 9 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Company contemporaneously with such amendment or termination) cause the Company to violate any federal securities laws, SEC rule or the rules of any national securities exchange or national securities association on which the Company's securities are listed.

10. **Other Recoupment Rights; No Additional Payments.** The Committee intends that this Policy will be applied to the fullest extent of the law. The Committee may require that any employment agreement, equity award agreement, or any other agreement entered into on or after the Effective Date shall, as a condition to the grant of any benefit thereunder, require an Executive Officer to agree to abide by the terms of this Policy. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company Group under applicable law, regulation or rule or pursuant to the terms of any similar policy of the Company Group or any provision in any employment agreement, equity award agreement, or other agreement or arrangement.

11. **Successors.** This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives.

CMS ENERGY

Consumers Energy

Count on Us®



To our Valued Shareholders:

I am pleased to report another year of strong operational, financial, and strategic performance at CMS Energy. Our results reflect disciplined execution across our electric and gas businesses, the achievement of constructive regulatory outcomes, and a sharp focus on affordability, all while delivering long-term value for investors. Our strategy – which starts with our customers at the center of everything we do – delivers

safe, reliable, affordable, clean, and equitable energy.

We continue to make significant customer investments through our ~\$8.5B electric Reliability Roadmap. By replacing aging infrastructure with more durable materials designed to withstand stronger winds and severe weather conditions, we are improving system performance and reducing long-term risk. As part of this work, we are expanding our vegetation management activities – addressing the leading cause of outages, shortening restoration time through better staging of materials, and increasing the amount of underground wire and pole replacements to harden the system. I continue to be pleased with the organization's progress and the improved service for our customers.

Our gas business continues to deliver reliable and affordable natural gas to heat homes and businesses during Michigan's cold winters. Our investment in 2025 of ~\$1B helped to ensure safe delivery to our customers while further reducing methane emissions. The team leverages some of the largest storage fields in the nation to buy gas in the summer when it is less expensive and deliver in the winter when it is needed most by our customers. This strategic advantage has allowed us to keep natural gas prices low – 28% below the national average. It is a great example of customer affordability in action!

We also continue to achieve constructive regulatory outcomes. In 2025, the Michigan Public Service Commission approved our 20-Year Renewable Energy Plan, which expands our long-term portfolio to 9GW of solar and 4GW of wind—positioning us to meet Michigan's 2023 Energy Law requirements for 60% renewables by 2035 and 100% clean energy by 2040. We also achieved constructive orders in both our electric and gas rate cases, supporting continued investment while protecting customer affordability.

Supporting Michigan's growth remains a priority. In 2025, Consumers Energy's Growth team connected ~450MW of new customer load, bringing new jobs and private investment to Michigan and our service area. As new load is added, fixed system costs are spread across a broader customer base, helping place downward pressure on customer bills over time.

Affordability continues to guide our operating discipline. Through our CE Way, we continue to eliminate waste and improve efficiency. In 2025, we delivered over \$100M of waste elimination savings for our customers, and our energy-efficiency program helped customers save ~\$1.2B over the life of the efficiency measure. This program was rated as top in the nation by the American Council for an Energy-Efficient Economy. This strong program ensures our customers' bills continue to be below the national average. Because when you use less, you pay less!

Finally, we continued our strong financial performance in the year and exceeded our adjusted earnings per share guidance, delivering \$3.61 per share. This is up over 8% from 2024's actual results and delivers the compounding of earnings you have come to expect from CMS Energy. We also raised our adjusted earnings per share guidance for 2026 by three cents to \$3.83 to \$3.90 per share, with continued confidence toward the high end. 2025 also marked the 20th year of growing the dividend.

These results build on more than two decades of consistent, industry-leading performance. Thank you for your continued trust and investment in CMS Energy as we work to build a more resilient, more affordable, and more prosperous energy future for Michigan.

Sincerely,



Garrick Rochow
President and CEO

This letter includes "forward-looking statements"; please refer to our SEC filings for information regarding the risks and uncertainties that could cause our actual results to differ materially. This letter also includes non-GAAP measures. Reconciliations to the most directly comparable GAAP measures are found immediately following this letter and on our website at cmsenergy.com.

CMS ENERGY CORPORATION
Reconciliation of GAAP Net Income to Non-GAAP Adjusted Net Income
(Unaudited)

In Millions, Except Per Share Amounts

Twelve Months Ended December 31, 2025	
Net Income Available to Common Stockholders	\$ 1,061
<i>Reconciling items:</i>	
Other exclusions from adjusted earnings**	19
Tax impact	(5)
State tax policy change	12
Adjusted net income – non-GAAP	<u>\$ 1,087</u>
Average Common Shares Outstanding - Diluted	301.0
Diluted Earnings Per Average Common Share	
Reported net income per share	\$ 3.53
<i>Reconciling items:</i>	
Other exclusions from adjusted earnings**	0.05
Tax impact	(0.01)
State tax policy change	0.04
Adjusted net income per share – non-GAAP	<u>\$ 3.61</u>

** Includes business optimization initiative, major enterprise resource planning software implementations, and unrealized gains or losses from mark-to-market adjustments, recognized in net income related to NorthStar Clean Energy's interest expense.

Management views adjusted (non-Generally Accepted Accounting Principles) earnings as a key measure of CMS Energy's present operating financial performance and uses adjusted earnings for external communications with analysts and investors. Internally, CMS Energy uses adjusted earnings to measure and assess performance. Because CMS Energy is not able to estimate the impact of specific line items, which have the potential to significantly impact, favorably or unfavorably, CMS Energy's reported earnings in future periods, CMS Energy is not providing reported earnings guidance nor is it providing a reconciliation for the comparable future period earnings. Adjustments could include items such as discontinued operations, asset sales, impairments, restructuring costs, business optimization initiative, major enterprise resource planning software implementations, changes in accounting principles, voluntary separation program, changes in federal and state tax policy, regulatory items from prior years, unrealized gains or losses from mark-to-market adjustments, recognized in net income related to NorthStar Clean Energy's interest expense, or other items. The adjusted earnings should be considered supplemental information to assist in understanding our business results, rather than as a substitute for reported earnings.

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2025

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File No.	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-9513	 <p align="center">CMS ENERGY CORPORATION (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550</p>	38-2726431
1-5611	 <p align="center">CONSUMERS ENERGY COMPANY (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550</p>	38-0442310

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
CMS Energy Corporation Common Stock, \$0.01 par value	CMS	New York Stock Exchange
CMS Energy Corporation 5.625% Junior Subordinated Notes due 2078	CMSA	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2078	CMSC	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2079	CMSD	New York Stock Exchange
CMS Energy Corporation Depositary Shares, each representing a 1/1,000th interest in a share of 4.200% Cumulative Redeemable Perpetual Preferred Stock, Series C	CMS PRC	New York Stock Exchange
Consumers Energy Company Cumulative Preferred Stock, \$100 par value: \$4.50 Series	CMS-PB	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

CMS Energy Corporation: Yes No **Consumers Energy Company:** Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

CMS Energy Corporation: Yes No **Consumers Energy Company:** Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

CMS Energy Corporation: Yes No **Consumers Energy Company:** Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

CMS Energy Corporation: Yes No **Consumers Energy Company:** Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

CMS Energy Corporation:		Consumers Energy Company:	
Large accelerated filer	<input checked="" type="checkbox"/>	Large accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Non-accelerated filer	<input checked="" type="checkbox"/>
Accelerated filer	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Smaller reporting company	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
Emerging growth company	<input type="checkbox"/>	Emerging growth company	<input type="checkbox"/>

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

CMS Energy Corporation: **Consumers Energy Company:**

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

CMS Energy Corporation: **Consumers Energy Company:**

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

CMS Energy Corporation: **Consumers Energy Company:**

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

CMS Energy Corporation: **Consumers Energy Company:**

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

CMS Energy Corporation: Yes No **Consumers Energy Company:** Yes No

The aggregate market value of CMS Energy voting and non-voting common equity held by non-affiliates was \$20.644 billion for the 297,980,694 CMS Energy Corporation Common Stock shares outstanding on June 30, 2025 based on the closing sale price of \$69.28 for CMS Energy Corporation Common Stock, as reported by the New York Stock Exchange on such date. There were no shares of Consumers common equity held by non-affiliates as of June 30, 2025.

There were 306,420,901 shares of CMS Energy Corporation Common Stock outstanding on January 16, 2026. On January 16, 2026, CMS Energy held all 84,108,789 outstanding shares of common stock of Consumers.

Documents incorporated by reference in Part III: CMS Energy's and Consumers' proxy statement relating to their 2026 Annual Meetings of Shareholders to be held May 8, 2026.

CMS Energy Corporation

Consumers Energy Company

Annual Reports on Form 10-K to the Securities and Exchange Commission for the Year Ended December 31, 2025

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Glossary

Certain terms used in the text and financial statements are defined below.

2023 Energy Law

Michigan's Public Acts 229, 230, 231, 233, 234, and 235 of 2023

ABATE

Association of Businesses Advocating Tariff Equity

ABO

Accumulated benefit obligation; the liabilities of a pension plan based on service and pay to date, which differs from the PBO in that it does not reflect expected future salary increases

AFUDC

Allowance for borrowed and equity funds used during construction

AOCI

Accumulated other comprehensive income (loss)

ARO

Asset retirement obligation

ASC 715

Financial Accounting Standards Board Accounting Standards Codification Topic 715, Compensation—Retirement Benefits

ASC 740

Financial Accounting Standards Board Accounting Standards Codification Topic 740, Income Taxes

ASP

Appliance Service Plan

ASU

Financial Accounting Standards Board Accounting Standards Update

Audit Committee

The Audit Committee of the Board, which is composed entirely of independent directors.

Aviator Wind

Aviator Wind Holdings, LLC, a VIE in which Aviator Wind Equity Holdings holds a Class B membership interest

Aviator Wind Equity Holdings

Aviator Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 51-percent interest

Bay Harbor

A residential/commercial real estate area located near Petoskey, Michigan, in which CMS Energy sold its interest in 2002

Bcf

Billion cubic feet

BG Solar Holdings

BG Solar Holdings, LLC, a VIE in which BG Solar Holdings I, LLC, a wholly owned subsidiary of Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, holds a Class B membership interest

Board

Board of Directors of CMS Energy and Consumers

CAO

Chief Accounting Officer

CCR

Coal combustion residual

CEO

Chief Executive Officer

CERCLA

Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended

CFO

Chief Financial Officer

CIO

Chief Information Officer

City-gate contract

An arrangement made for the point at which a local distribution company physically receives gas from a supplier or pipeline

Clean Air Act

Federal Clean Air Act of 1963, as amended

Clean Water Act

Federal Water Pollution Control Act of 1972, as amended

CMS Capital

CMS Capital, L.L.C., a wholly owned subsidiary of CMS Energy

CMS Energy

CMS Energy Corporation and its consolidated subsidiaries, unless otherwise noted; the parent of Consumers and NorthStar Clean Energy

CMS ERM

CMS Energy Resource Management Company a wholly owned subsidiary of NorthStar Clean Energy

CMS Gas Transmission

CMS Gas Transmission Company, a wholly owned subsidiary of NorthStar Clean Energy

CMS Land

CMS Land Company, a wholly owned subsidiary of CMS Capital, L.L.C., a wholly owned subsidiary of CMS Energy

Consumers

Consumers Energy Company and its consolidated subsidiaries, unless otherwise noted; a wholly owned subsidiary of CMS Energy

Consumers 2014 Securitization Funding

Consumers 2014 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Consumers 2023 Securitization Funding

Consumers 2023 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Covert Generating Station

A 1,200-MW natural gas-fueled generation station that was acquired by Consumers in 2023 from New Covert Generating Company, LLC, a non-affiliated company

Craven

Craven County Wood Energy Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

CSAPR

Cross-State Air Pollution Rule of 2011, as amended

DB Pension Plan A

Defined benefit pension plan of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries, created as of December 31, 2017 for active employees who were covered under the defined benefit pension plan that closed in 2005

DB Pension Plan B

Defined benefit pension plan of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries, amended as of December 31, 2017 to include only retired and former employees who were covered under the defined benefit pension plan that closed in 2005

DB Pension Plans

Defined benefit pension plans of CMS Energy and Consumers, comprising DB Pension Plan A and DB Pension Plan B

DB SERP

Defined Benefit Supplemental Executive Retirement Plan

DCCP

Defined Company Contribution Plan

DC SERP

Defined Contribution Supplemental Executive Retirement Plan

Delta Solar Equity Holdings

Delta Solar Equity Holdings, LLC, a VIE in which Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

DIG

Dearborn Industrial Generation, L.L.C., a wholly owned subsidiary of Dearborn Industrial Energy, L.L.C., a wholly owned subsidiary of NorthStar Clean Energy

Dodd-Frank Act

Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010

DOE

U.S. Department of Energy

DTE Electric

DTE Electric Company, a non-affiliated company

EEI

Edison Electric Institute, an association representing all U.S. investor-owned electric companies

EGLE

Michigan Department of Environment, Great Lakes, and Energy

Electric Supply Plan

Consumers' long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers; this plan is outlined in Consumers' integrated resource plan and incorporates the Renewable Energy Plan

Endangered Species Act

Federal Endangered Species Act of 1973, as amended

EnerBank

EnerBank USA, a wholly owned subsidiary of CMS Capital until October 1, 2021

Energy waste reduction

The reduction of energy consumption through energy efficiency and demand-side energy conservation, as established under Michigan law

EPA

U.S. Environmental Protection Agency

EPS

Earnings per share

ERCOT

Electric Reliability Council of Texas

ERP

Enterprise Resource Planning software

Exchange Act

Securities Exchange Act of 1934

Federal Power Act

Federal Power Act of 1920

FERC

Federal Energy Regulatory Commission

First Mortgage Bond Indenture

Indenture dated as of September 1, 1945 between Consumers and The Bank of New York Mellon, as Trustee, as amended and supplemented

FTR

Financial transmission right

GAAP

U.S. Generally Accepted Accounting Principles

GCC

Gas Customer Choice, which allows gas customers to purchase gas from alternative suppliers

GCR

Gas cost recovery

Genesee

Genesee Power Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Grayling

Grayling Generating Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

GW

Gigawatt, a unit of energy equal to 1 billion watts

GWh

Gigawatt-hour, a unit of energy equal to 1 billion watt-hours

Internal Revenue Code

Internal Revenue Code of 1986, as amended

IRS

Internal Revenue Service

IT

Information technology

J.H. Campbell

J.H. Campbell Generating Complex, a three-unit coal-fueled electric generating facility comprised of Units 1 and 2, which are wholly owned by Consumers, and Unit 3, which Consumers jointly owns with the Michigan Public Power Agency, holding a 4.80-percent interest, and Wolverine Power, holding a 1.89-percent interest, each a non-affiliated company

kV

Thousand volts, a unit used to measure the difference in electrical pressure along a current

kVA

Thousand volt-amperes, a unit used to reflect the electrical power capacity rating of equipment or a system

kWh

Kilowatt-hour, a unit of energy equal to 1,000 watt-hours

Ludington

Ludington pumped-storage plant, jointly owned by Consumers and DTE Electric

MATS

Mercury and Air Toxics Standards, which limit mercury, acid gases, and other toxic pollution from coal-fueled and oil-fueled power plants

MCV Facility

A 1,647-MW natural gas-fueled, combined-cycle cogeneration facility operated by the MCV Partnership

MCV Partnership

Midland Cogeneration Venture Limited Partnership, a non-affiliated company

MCV PPA

PPA between Consumers and the MCV Partnership

METC

Michigan Electric Transmission Company, LLC, a non-affiliated company

MGP

Manufactured gas plant

Migratory Bird Treaty Act

Migratory Bird Treaty Act of 1918, as amended

MISO

Midcontinent Independent System Operator, Inc.

MISO Tariff

MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff

Mothball

To place a generating unit into a state of extended reserve shutdown in which the unit is inactive and unavailable for service for a specified period, during which the unit can be brought back into service after receiving appropriate notification and completing any necessary maintenance or other work; generation owners in MISO must request approval to mothball a unit, and MISO then evaluates the request for reliability impacts

MPSC

Michigan Public Service Commission

MRV

Market-related value of plan assets

MW

Megawatt, a unit of power equal to 1 million watts

MWh

Megawatt-hour, a unit of energy equal to 1 million watt-hours

NAAQS

National Ambient Air Quality Standards

Natural Gas Act

Natural Gas Act of 1938

NERC

North American Electric Reliability Corporation, a non-affiliated company responsible for developing and enforcing reliability standards, monitoring the bulk power system, and educating and certifying industry personnel

Newport Solar Holdings

Newport Solar Holdings III, LLC, a VIE in which Newport Solar Equity Holdings LLC, a wholly owned subsidiary of Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, holds a Class B membership interest

NorthStar Clean Energy

NorthStar Clean Energy Company and its consolidated subsidiaries, unless otherwise noted; a wholly owned subsidiary of CMS Energy

NO_x

Nitrogen oxides

NPDES

National Pollutant Discharge Elimination System, a permit system for regulating point sources of pollution under the Clean Water Act

NREPA

Part 201 of Michigan's Natural Resources and Environmental Protection Act of 1994, as amended

NWO Holdco

NWO Holdco, L.L.C., a VIE in which NWO Holdco I, LLC, a wholly owned subsidiary of NWO Wind Equity Holdings, LLC, holds a Class B membership interest

NWO Wind Equity Holdings

NWO Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

OBBBA

Federal One Big Beautiful Bill Act of 2025

OPEB

Other post-employment benefits

OPEB Plan

Postretirement health care and life insurance plans of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries

OSHA

Occupational Safety and Health Administration

PBO

Projected benefit obligation

PCB

Polychlorinated biphenyl

PFAS

Per- and polyfluoroalkyl substances

PISP

Performance Incentive Stock Plan

PJM

PJM Interconnection Inc.

PPA

Power purchase agreement

PSCR

Power supply cost recovery

PURPA

Public Utility Regulatory Policies Act of 1978

RCRA

Federal Resource Conservation and Recovery Act of 1976

REC

Renewable energy credit

Reliability Roadmap

Consumers' five-year strategy to improve its electric distribution system and the reliability of the grid; this plan was filed with the MPSC in 2023, and is an update to Consumers' previous Electric Distribution Infrastructure Investment Plan filed in 2021

ROA

Retail Open Access, which allows electric generation customers to choose alternative electric suppliers pursuant to Michigan's Public Acts 141 and 142 of 2000, as amended

S&P

Standard & Poor's Financial Services LLC

SEC

U.S. Securities and Exchange Commission

Securitization

A financing method authorized by statute and approved by the MPSC which allows a utility to sell its right to receive a portion of the rate payments received from its customers for the repayment of securitization bonds issued by a special-purpose entity affiliated with such utility

SOFR

Secured overnight financing rate calculated and published by the Federal Reserve Bank of New York

TAES

Toshiba America Energy Systems Corporation, a non-affiliated company

TBJH

TBJH Inc., a non-affiliated company

TCJA

Tax Cuts and Jobs Act of 2017

Term SOFR

The rate per annum that is a forward-looking term rate based on SOFR

T.E.S. Filer City

T.E.S. Filer City Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Toshiba

Toshiba Corporation, a non-affiliated company

Toshiba International

Toshiba International Corporation, a non-affiliated company

USW

United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO-CLC

UWUA

Utility Workers Union of America, AFL-CIO

VEBA trust

Voluntary employees' beneficiary association trusts accounts established specifically to set aside employer-contributed assets to pay for future expenses of the OPEB Plan

VIE

Variable interest entity

Wolverine Power

Wolverine Power Supply Cooperative, Inc., a non-affiliated company

Filing Format

This combined Form 10-K is separately filed by CMS Energy and Consumers. Information in this combined Form 10-K relating to each individual registrant is filed by such registrant on its own behalf. Consumers makes no representation regarding information relating to any other companies affiliated with CMS Energy other than its own subsidiaries.

CMS Energy is the parent holding company of several subsidiaries, including Consumers and NorthStar Clean Energy. None of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers) has any obligation in respect of Consumers' debt securities or preferred stock and holders of such securities should not consider the financial resources or results of operations of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers and its own subsidiaries (in relevant circumstances)) in making a decision with respect to Consumers' debt securities or preferred stock. Similarly, neither Consumers nor any other subsidiary of CMS Energy has any obligation in respect of securities of CMS Energy.

Forward-looking Statements and Information

This Form 10-K and other CMS Energy and Consumers disclosures may contain forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. The use of "anticipates," "assumes," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "might," "objectives," "plans," "possible," "potential," "predicts," "projects," "seeks," "should," "targets," "will," and other similar words is intended to identify forward-looking statements that involve risk and uncertainty. This discussion of potential risks and uncertainties is designed to highlight important factors that may impact CMS Energy's and Consumers' businesses and financial outlook. CMS Energy and Consumers have no obligation to update or revise forward-looking statements regardless of whether new information, future events, or any other factors affect the information contained in the statements. These forward-looking statements are subject to various factors that could cause CMS Energy's and Consumers' actual results to differ materially from the results anticipated in these statements. These factors include, but are not limited to, the following, all of which are potentially significant:

- the impact and effect of recent events, such as worsening trade relations, geopolitical tensions, war, acts of terrorism, and the responses to these events, and related economic disruptions including, but not limited to, inflation, energy price volatility, tariffs, and supply chain disruptions
- the impact of new or modified regulation by the MPSC, FERC, and other applicable governmental proceedings and regulations, including any associated impact on electric or gas rates or rate structures
- potentially adverse regulatory treatment, effects of a failure to receive timely regulatory orders that are or could come before the MPSC, FERC, or other governmental authorities, or effects of a government shutdown
- changes in the performance of or regulations applicable to MISO, METC, pipelines, railroads, vessels, or other service providers that CMS Energy, Consumers, or any of their affiliates rely on to serve their customers
- federal or executive actions, the adoption of or challenges to federal or state laws or regulations or changes in applicable laws, rules, regulations, principles, or practices, or in their interpretation, such as those related to energy policy, ROA, the Public Utility Regulatory Policies Act of 1978, infrastructure integrity or security, cybersecurity, gas pipeline safety, gas pipeline capacity, energy waste reduction, the financial compensation mechanism, the environment, regulation or

deregulation, reliability, health care reforms, taxes, tax credits, accounting matters, tariffs, climate change, air emissions, renewable energy, the Dodd-Frank Act, and other business issues that could have an impact on CMS Energy's, Consumers', or any of their affiliates' businesses or financial results

- factors affecting, disrupting, interrupting, or otherwise impacting CMS Energy's or Consumers' facilities, utility infrastructure, operations, or backup systems, such as costs and availability of personnel, equipment, and materials; weather and climate, including catastrophic weather-related damage and extreme temperatures; natural disasters; fires; smoke; scheduled or unscheduled equipment outages; maintenance or repairs; contractor performance; environmental incidents; failures of equipment or materials; electric transmission and distribution or gas pipeline system constraints; interconnection requirements; political and social unrest; general strikes; the government and/or paramilitary response to political or social events; changes in trade policies, regulations, or tariffs; accidents; explosions; physical disasters; global pandemics; cyber incidents; physical or cyber attacks; vandalism; war or terrorism; and the ability to obtain or maintain insurance coverage for these events
- the ability of CMS Energy and Consumers to execute cost-reduction strategies and/or convert economic development opportunities
- potentially adverse regulatory or legal interpretations or decisions regarding environmental matters, or delayed regulatory treatment or permitting decisions that are or could come before agencies such as EGLE, the EPA, FERC, and/or the U.S. Army Corps of Engineers, and potential environmental remediation costs associated with these interpretations or decisions, including those that may affect Consumers' coal ash management or routine maintenance, repair, and replacement classification under New Source Review, a construction-permitting program under the Clean Air Act
- changes in energy markets, including availability, price, and seasonality of electric capacity and energy and the timing and extent of changes in commodity prices and availability and deliverability of coal, natural gas, natural gas liquids, electricity, oil, gasoline, diesel fuel, and certain related products
- the price of CMS Energy common stock, the credit ratings of CMS Energy and Consumers, capital and financial market conditions, and the effect of these market conditions on CMS Energy's and Consumers' interest costs and access to the capital markets, including availability of financing to CMS Energy, Consumers, or any of their affiliates
- the ability of CMS Energy and Consumers to execute their financing strategies
- the investment performance of the assets of CMS Energy's and Consumers' pension and benefit plans, the discount rates, mortality assumptions, and future medical costs used in calculating the plans' obligations, and the resulting impact on future funding requirements
- the impact of the economy, particularly in Michigan, and potential future volatility in the financial and credit markets on CMS Energy's, Consumers', or any of their affiliates' revenues, ability to collect accounts receivable from customers, or cost and availability of capital
- changes in the economic and financial viability of CMS Energy's and Consumers' suppliers, customers, and other counterparties and the continued ability of these third parties, including those in bankruptcy, to meet their obligations to CMS Energy and Consumers

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- population changes in the geographic areas where CMS Energy and Consumers conduct business
- national, regional, and local economic, competitive, and regulatory policies, conditions, and developments
- loss of customer demand for electric generation supply to alternative electric suppliers, the creation of municipal utilities, increased use of self-generation including distributed generation, energy waste reduction, or energy storage
- loss of customer demand for natural gas due to alternative technologies or fuels or electrification
- the ability of Consumers to meet increased renewable energy demand due to customers seeking to meet their own sustainability goals in a timely and cost-efficient manner
- the reputational or other impact on CMS Energy and Consumers of the failure to meet the renewable or clean energy standards required by the 2023 Energy Law or to achieve or make timely progress on their greenhouse gas reduction goals related to reducing their impact on climate change
- adverse consequences of employee, director, or third-party fraud or non-compliance with codes of conduct or with laws or regulations
- federal regulation of electric sales, including periodic re-examination by federal regulators of CMS Energy's and Consumers' market-based sales authorizations
- any event, change, development, occurrence, or circumstance that could impact the implementation of the Electric Supply Plan, including any action by a regulatory authority or other third party to prohibit, delay, or impair the implementation of the Electric Supply Plan
- the ability to meet increases in electric demand associated with data centers, or alternatively, the risk that anticipated demand growth from data center expansion may not materialize as expected
- changes associated with artificial intelligence technologies and related sectors, including the risk that a significant decline in investor confidence could lead to broader economic disruption, reductions in customer demand, tightening of capital markets, higher financing costs, or other downstream impacts
- the availability, cost, coverage, and terms of insurance, the stability of insurance providers, and the ability of Consumers to recover the costs of any insurance from customers
- the effectiveness of CMS Energy's and Consumers' risk management policies, procedures, and strategies, including strategies to hedge risk related to interest rates and future prices of electricity, natural gas, and other energy-related commodities
- factors affecting development of electric generation projects, gas transmission, and gas and electric distribution infrastructure replacement, conversion, and expansion projects, including factors related to project site identification, construction material availability, quality, and pricing, tariffs, embargoes on equipment, supply chain disruptions, schedule delays, interconnection delays, availability of qualified construction personnel, permitting, acquisition of property rights, community opposition, environmental regulations, performance of contractors and counterparties, and government actions
- changes or disruption in fuel supply, including but not limited to supplier bankruptcy and delivery disruptions

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- potential costs, lost revenues, reputational harm, or other consequences resulting from misappropriation of assets or sensitive information, corruption of data, or operational disruption in connection with a cyberattack or other cyber incident
- potential disruption to, interruption or failure of, or other impacts on IT backup or disaster recovery systems
- technological developments in energy production, storage, delivery, usage, and metering
- the ability to implement and integrate technology successfully, including artificial intelligence
- the impact of CMS Energy's and Consumers' integrated business software system and its effects on their operations, including utility customer billing and collections
- adverse consequences resulting from any past, present, or future assertion of indemnity or warranty claims associated with assets and businesses previously owned by CMS Energy or Consumers, including claims resulting from attempts by foreign or domestic governments to assess taxes on or to impose environmental liability associated with past operations or transactions
- the outcome, cost, and other effects of any legal or administrative claims, proceedings, investigations, or settlements
- the reputational impact on CMS Energy and Consumers of operational incidents, violations of corporate policies, regulatory violations, inappropriate use of social media, and other events
- restrictions imposed by various financing arrangements and regulatory requirements on the ability of Consumers and other subsidiaries of CMS Energy to transfer funds to CMS Energy in the form of cash dividends, loans, or advances
- earnings volatility resulting from the application of fair value accounting to certain energy commodity contracts or interest rate contracts
- changes in financial or regulatory accounting principles or policies or interpretation of principles or policies
- other matters that may be disclosed from time to time in CMS Energy's and Consumers' SEC filings, or in other public documents

All forward-looking statements should be considered in the context of the risk and other factors described above and as detailed from time to time in CMS Energy's and Consumers' SEC filings. For additional details regarding these and other uncertainties, see Item 1A. Risk Factors; Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook; and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Part I

Item 1. Business

General

CMS Energy

CMS Energy was formed as a corporation in Michigan in 1987 and is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy, primarily a domestic independent power producer and marketer. Consumers' customer base consists of a mix of primarily residential, commercial, and diversified industrial customers. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production.

CMS Energy manages its businesses by the nature of services each provides, and operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers' consolidated operations account for the substantial majority of CMS Energy's total assets, income, and operating revenue. CMS Energy's consolidated operating revenue was \$8.5 billion in 2025, and \$7.5 billion in 2024 and 2023.

For further information about operating revenue, income, and assets and liabilities attributable to all of CMS Energy's business segments and operations, see Item 8. Financial Statements and Supplementary Data—CMS Energy Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

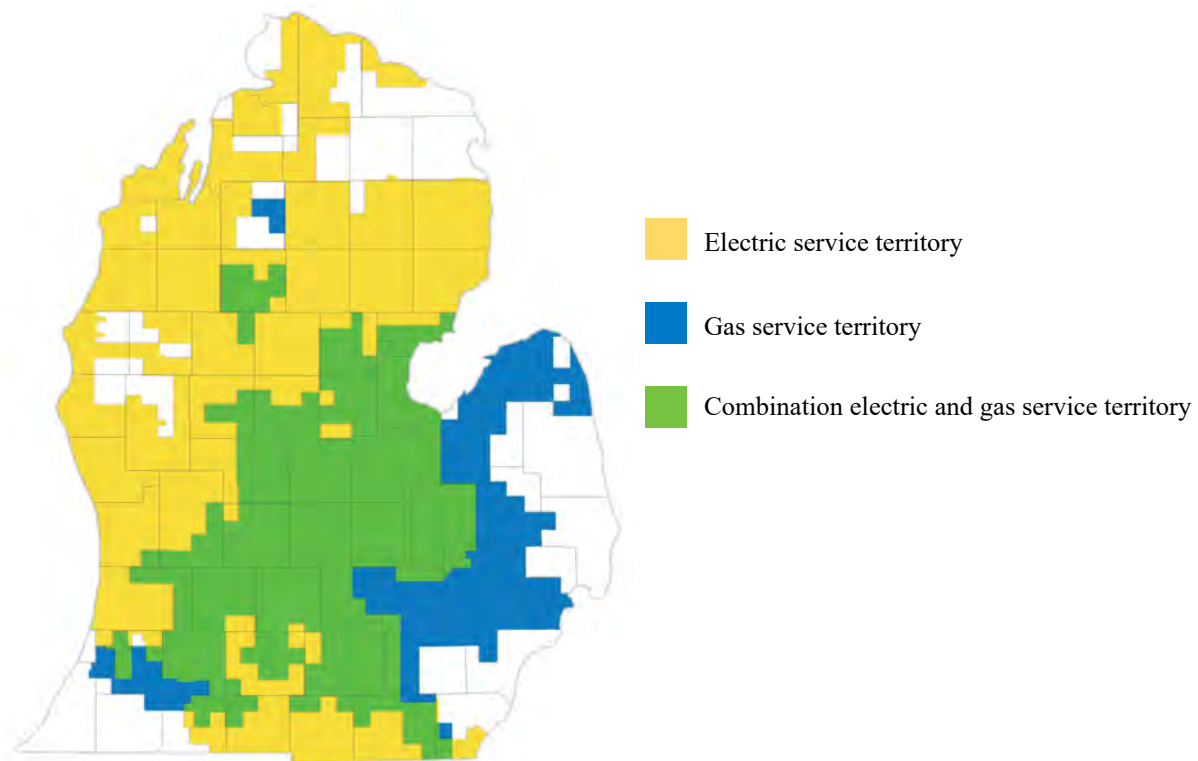
Consumers

Consumers has served Michigan customers since 1886. Consumers was incorporated in Maine in 1910 and became a Michigan corporation in 1968. Consumers owns and operates electric generation and distribution facilities and gas transmission, storage, and distribution facilities. It provides electricity and/or natural gas to 6.8 million of Michigan's 10 million residents. Consumers' rates and certain other aspects of its business are subject to the jurisdiction of the MPSC and FERC, as well as to NERC reliability standards, as described in CMS Energy and Consumers Regulation.

Consumers' consolidated operating revenue was \$8.1 billion in 2025, and \$7.2 billion in 2024 and 2023. For further information about operating revenue, income, and assets and liabilities attributable to Consumers' electric and gas utility operations, see Item 8. Financial Statements and Supplementary Data—Consumers Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Consumers owns its principal properties in fee, except that most electric lines, gas mains, and renewable generation projects are located below or adjacent to public roads or on land owned by others and are accessed by Consumers through easements, leases, and other rights. Almost all of Consumers' properties are subject to the lien of its First Mortgage Bond Indenture. For additional information on Consumers' properties, see Business Segments—Consumers Electric Utility—Electric Utility Properties and Consumers Gas Utility—Gas Utility Properties.

In 2025, Consumers served 1.9 million electric customers and 1.8 million gas customers in Michigan’s Lower Peninsula. Presented in the following map are Consumers’ service territories:



CMS Energy and Consumers—The Triple Bottom Line

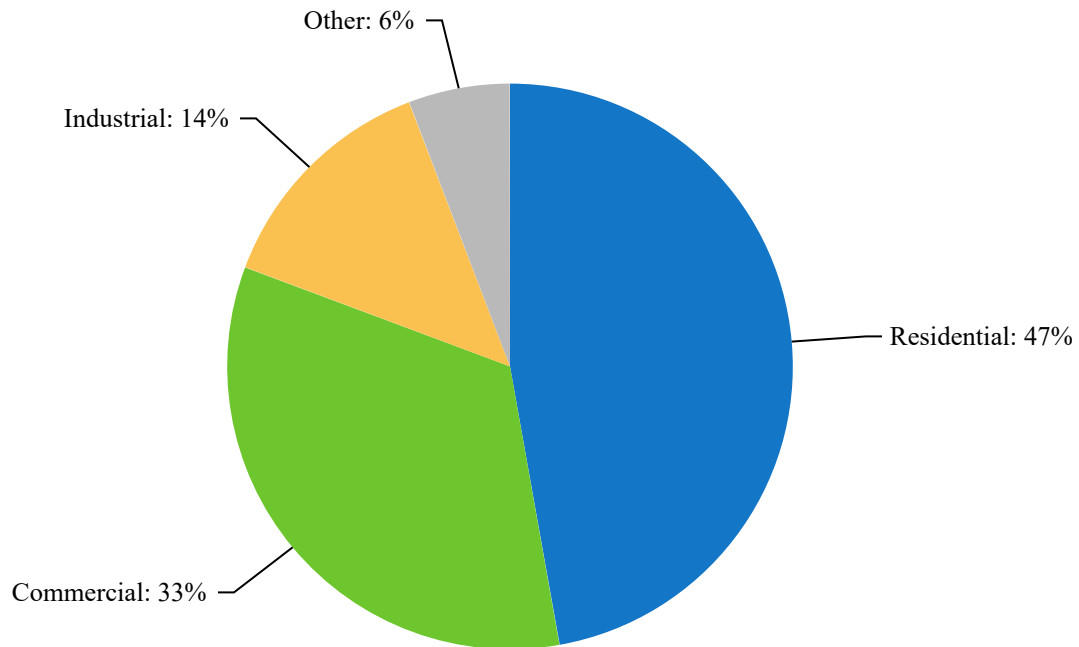
For information regarding CMS Energy’s and Consumers’ purpose and impact on the “triple bottom line” of people, planet, and prosperity, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview.

Business Segments

Consumers Electric Utility

Electric Utility Operations: Consumers’ electric utility operations, which include the generation, purchase, distribution, and sale of electricity, generated operating revenue of \$5.6 billion in 2025, \$5.1 billion in 2024, and \$4.7 billion in 2023. Consumers’ electric utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigan’s Lower Peninsula.

Presented in the following illustration is Consumers' 2025 electric utility operating revenue of \$5.6 billion by customer class:

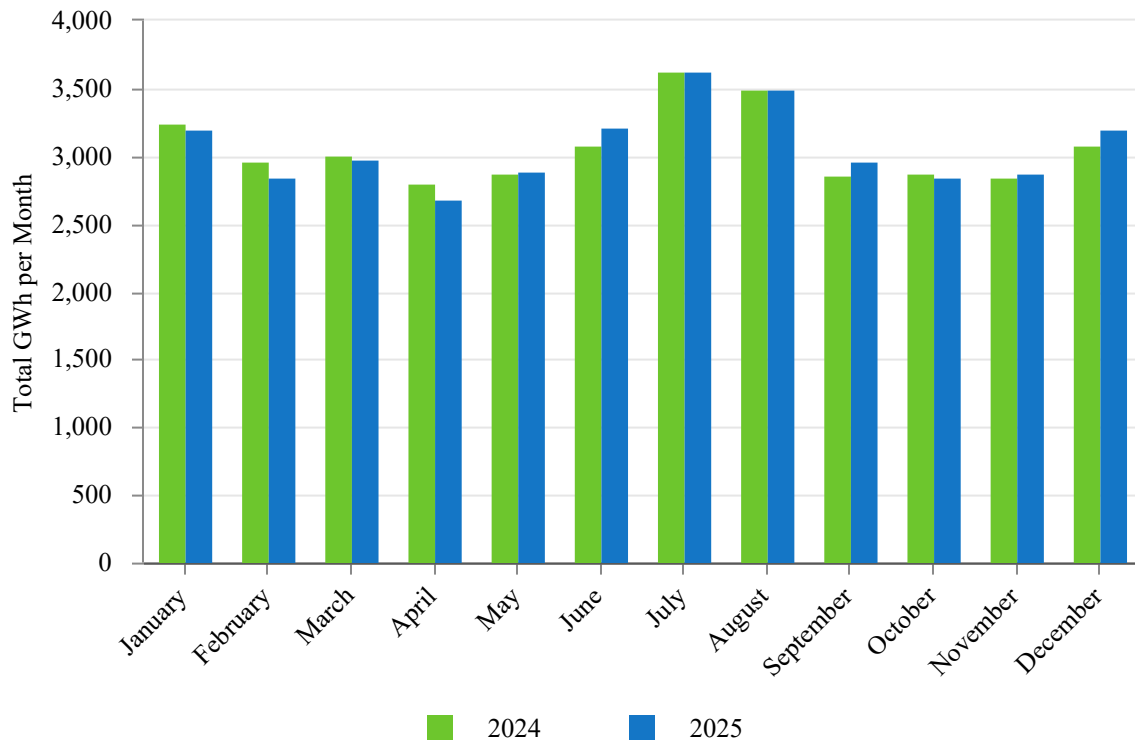


Consumers' electric utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers' largest customers is not reasonably likely to have a material adverse effect on Consumers' financial condition.

In 2025, Consumers' electric deliveries were 37 billion kWh, which included ROA deliveries of 3 billion kWh, resulting in net bundled sales of 34 billion kWh. In 2024, Consumers' electric deliveries were 37 billion kWh, which included ROA deliveries of 4 billion kWh, resulting in net bundled sales of 33 billion kWh.

Consumers' electric utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment.

Presented in the following illustration are Consumers’ monthly weather-normalized electric deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including ROA deliveries, during 2025 and 2024:



Consumers’ 2025 summer peak demand was 8,500 MW, which included ROA demand of 552 MW. For the 2024-2025 winter season, Consumers’ peak demand was 5,755 MW, which included ROA demand of 449 MW. As required by MISO reserve margin requirements, Consumers owns or controls, through long-term PPAs, short-term capacity purchases, and auction capacity purchases, all of the capacity required to supply its projected firm peak load and necessary reserve margin for summer 2026.

Electric Utility Properties: Consumers owns and operates electric generation and distribution facilities. For details about Consumers’ electric generation facilities, see the Electric Utility Generation and Supply Mix section that follows this Electric Utility Properties section. Consumers’ distribution system consists of:

- 263 miles of high-voltage distribution overhead lines operating at 138 kV
- 4 miles of high-voltage distribution underground lines operating at 138 kV
- 4,619 miles of high-voltage distribution overhead lines operating at 46 kV and 69 kV
- 18 miles of high-voltage distribution underground lines operating at 46 kV
- 82,854 miles of electric distribution overhead lines
- 10,027 miles of underground distribution lines
- 1,102 substations with an aggregate transformer capacity of 29 million kVA

Consumers is interconnected to the interstate high-voltage electric transmission system owned by METC and operated by MISO. Consumers is also interconnected to neighboring utilities and to other transmission systems.

Electric Utility Generation and Supply Mix: Consumers’ Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers’ Renewable Energy Plan. The Electric Supply Plan

is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives.

To meet these objectives, Consumers is executing a multi-faceted strategy. This strategy involves taking steps to end the use of coal, including the retirement of the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, in 2023 and obtaining MPSC approval to retire J.H. Campbell, totaling 1,407 MW of nameplate capacity. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For a more detailed discussion of the emergency orders, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

To continue providing controllable sources of electricity to customers, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023 and has solicited additional capacity from controllable sources of electricity to customers.

Consumers' updates to its Renewable Energy Plan include up to 9,000 MW of both purchased and owned solar energy resources and up to 4,000 MW of wind energy resources. Coupled with updates to its integrated resource plan, these actions position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040. For further information on Consumers' progress towards reducing carbon emissions and towards meeting the requirements of the 2023 Energy Law, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview and Outlook—Consumers Electric Utility Outlook and Uncertainties.

Presented in the following table are details about Consumers’ 2025 electric generation and supply mix:

Name and Location (Michigan)	Number of Units and Year Entered Service	2025 Generation Capacity ¹ (MW)	2025 Electric Supply (GWh)
<i>Coal steam generation</i>			
J.H. Campbell 1 & 2 – West Olive ²	2 Units, 1962-1967	—	2,568
J.H. Campbell 3 – West Olive ^{2,3}	1 Unit, 1980	—	4,752
		—	7,320
<i>Oil/Gas steam generation</i>			
D.E. Karn 3 & 4 – Essexville	2 Units, 1975-1977	1,189	106
<i>Hydroelectric</i>			
Ludington – Ludington	6 Units, 1973	1,119 ⁴	(360) ⁵
Conventional hydro generation ⁶	35 Units, 1906-1949	75	344
		1,194	(16)
<i>Gas combined cycle</i>			
Covert Generating Station – Covert	3 Units, 2004	1,090	7,357
Jackson – Jackson	1 Unit, 2002	531	1,979
Zeeland – Zeeland	3 Units, 2002	534	3,952
		2,155	13,288
<i>Gas combustion turbines</i>			
Zeeland (simple cycle) – Zeeland	2 Units, 2001	314	1,373
<i>Wind generation</i>			
Crescent Wind Farm – Hillsdale County	2021	150	362
Cross Winds [®] Energy Park – Tuscola County	2014-2019	231	728
Gratiot Farms Wind Project – Gratiot County	2020	150	345
Heartland Farms Wind Project – Gratiot County	2023	200	470
Lake Winds [®] Energy Park – Mason County	2012	101	251
		832	2,156
<i>Solar generation</i>			
Solar Gardens – Allendale, Cadillac, Kalamazoo, and Grand Rapids	2016-2021	5	7
Muskegon Solar Energy Center	2025	250	2
		255	9
<i>Battery storage capacity</i>			
Batteries – Grand Rapids, Cadillac, Kalamazoo, and Standish	4 Units, 2021-2022	1	—
Total owned generation		5,940	24,236
<i>Purchased power⁷</i>			
Coal generation – T.E.S. Filer City		63	352
Gas generation – MCV Facility ⁸		1,240	7,206
Other gas generation		254	1,233
Wind generation		384	1,026
Solar generation		1,017	1,355
Battery storage		100	(8) ⁹
Other renewable generation		192	1,005
		3,250	12,169
Net interchange power ¹⁰		—	(502)
Total purchased and interchange power		3,250	11,667
Total supply		9,190	35,903
Less distribution and transmission loss			2,094
Total net bundled sales			33,809

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- ¹ With the exception of wind and solar generation, the amount represents generation capacity during the summer months (planning year 2025 capacity as reported to MISO and limited by interconnection service limits). For wind and solar generation, the amount represents installed capacity.
- ² Consumers planned to retire these generating units in May 2025. However, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Under those emergency orders, Consumers has continued to operate these units for the benefit of MISO's North and Central regions. Of the 7,320 GWh generated by these units during 2025, Consumers supplied 3,608 GWh of electricity to MISO in order to comply with the emergency orders. For a more detailed discussion of the emergency orders, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.
- ³ Represents Consumers' share of the electric supply of the J.H. Campbell 3 unit, net of the 6.69-percent ownership interest of the Michigan Public Power Agency and Wolverine Power, each a non-affiliated company.
- ⁴ Represents Consumers' 51-percent share of the capacity of Ludington. DTE Electric holds the remaining 49-percent ownership interest.
- ⁵ Represents Consumers' share of net pumped-storage generation. The pumped-storage facility consumes electricity to pump water during off-peak hours for storage in order to generate electricity later during peak-demand hours.
- ⁶ In 2025, Consumers entered an agreement to sell the 13 hydroelectric dams that comprise the 35 generating units. For a more detailed discussion of this transaction, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 20, Exit Activities and Asset Sales.
- ⁷ Represents purchases under long-term PPAs, including capacity purchases.
- ⁸ For information about Consumers' long-term PPA related to the MCV Facility, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.
- ⁹ Reflects net delivered energy from storage operations, after accounting for charging losses.
- ¹⁰ Represents the net amount of generation offered to and purchased from the MISO energy market.

Presented in the following table are the sources of Consumers’ electric supply for the last three years:

Years Ended December 31	2025	2024	2023
<i>GWh</i>			
<i>Owned generation</i>			
Gas	14,661	14,856	11,221
Coal	7,320	7,932	6,884
Renewable energy	2,509	2,521	1,993
Oil	106	96	2
Net pumped storage ¹	(360)	(458)	(349)
Total owned generation	24,236	24,947	19,751
<i>Purchased power²</i>			
Gas generation	8,439	9,662	7,244
Renewable energy generation	3,386	3,138	2,585
Battery storage ³	(8)	—	—
Coal generation	352	230	318
Net interchange power ⁴	(502)	(2,715)	4,532
Total purchased and interchange power	11,667	10,315	14,679
Total supply	35,903	35,262	34,430

¹ Represents Consumers’ share of net pumped-storage generation. During 2025, the pumped-storage facility consumed 1,351 GWh of electricity to pump water during off-peak hours for storage in order to generate 991 GWh of electricity later during peak-demand hours.

² Represents purchases under long-term PPAs, including capacity purchases.

³ Reflects net delivered energy from storage operations, after accounting for charging losses.

⁴ Represents the net amount of generation offered to and purchased from the MISO energy market.

During 2025, 41 percent of Consumers’ electric supply was generated by its natural gas-fueled generating units, which burned 105 Bcf of natural gas and produced a combined total of 14,661 GWh of electricity.

In order to obtain the gas it needs for electric generation fuel, Consumers’ electric utility purchases gas from the market near the time of consumption, at prices that allow it to compete in the electric wholesale market. For the Covert Generating Station and Jackson and Zeeland plants, Consumers utilizes an agent that owns firm transportation rights to each plant to purchase gas from the market and transport the gas to the facilities. For units 3 & 4 of D.E. Karn, Consumers holds gas transportation contracts to transport to the plant gas that Consumers or an agent purchase from the market.

During 2025, Consumers acquired 32 percent of its electric supply through long-term PPAs and the MISO energy market. Consumers offers its generation into the MISO energy market on a day-ahead and real-time basis and bids for power in the market to serve the demand of its customers. Consumers supplements its generation capability with purchases from the MISO energy market.

At December 31, 2025, Consumers had future commitments to purchase capacity and energy under long-term PPAs with various generating plants. These contracts require monthly capacity payments based on the plants’ availability or deliverability. The payments for 2026 through 2060 are estimated to total \$17.0 billion and, for each of the next five years, range from \$0.9 billion to \$1.0 billion annually. These amounts may vary depending on plant availability and fuel costs. For further information about

Consumers' future capacity and energy purchase obligations, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Other Material Cash Requirements and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.

During 2025, 20 percent of Consumers' electric supply was generated by its coal-fueled generating units, which burned 4 million tons of coal and produced a combined total of 7,320 GWh of electricity. Consumers planned to exit coal generation in 2025 but the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Of the 7,320 GWh generated by these units during 2025, Consumers supplied 3,608 GWh of electricity to MISO in order to comply with the emergency orders. For a more detailed discussion of the emergency orders, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

In order to obtain the coal it needs, Consumers has historically entered into physical coal supply contracts, leased a fleet of railcars, and secured transportation contracts with various companies to provide rail services for delivery of purchased coal to Consumers' generating facilities. Following the emergency orders, Consumers was able to utilize relationships with existing suppliers in order to procure additional supply and maintain railcar leases and transportation contracts past the planned shutdown date of May 2025. At December 31, 2025, Consumers had future commitments to purchase and deliver coal for the remainder of the then-current emergency order, with options to extend these agreements if needed.

Electric Utility Competition: Consumers' electric utility business is subject to actual and potential competition from many sources, in both the wholesale and retail markets, as well as in electric generation, electric delivery, and retail services.

Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers' sales, with certain exceptions. At December 31, 2025, electric deliveries under the ROA program were at the 10-percent limit. Fewer than 300 of Consumers' electric customers purchased electric generation service under the ROA program. For additional information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties.

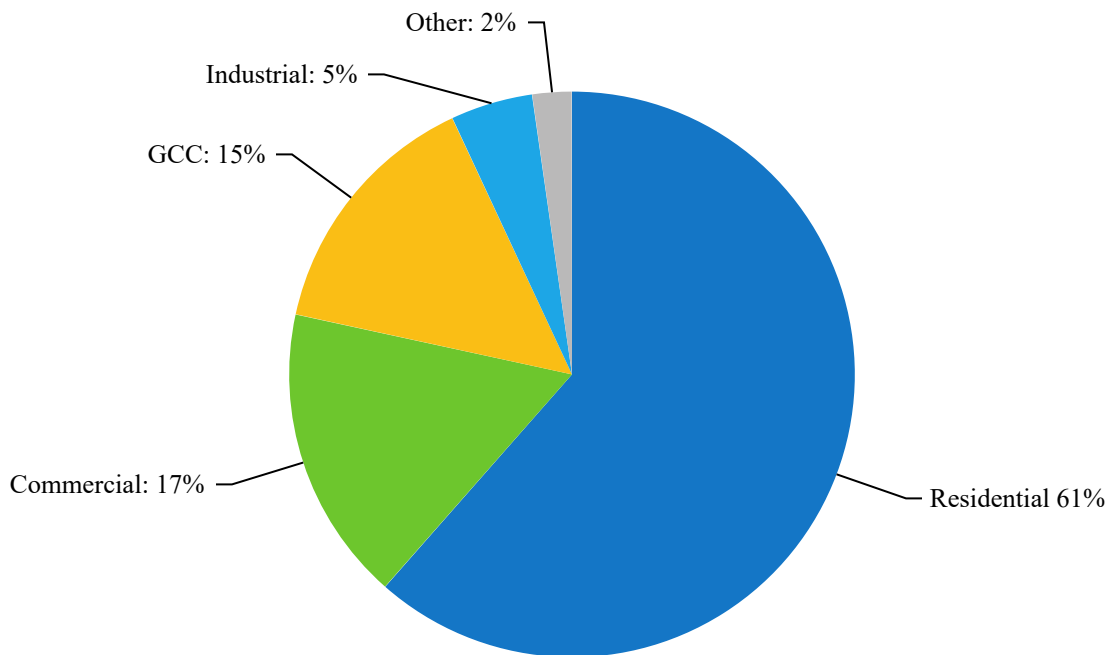
Consumers also faces competition or potential competition associated with data center expansion and industrial customer relocation outside of Consumers' service territory for economic reasons; municipalities owning or operating competing electric delivery systems; and customer self-generation. Consumers addresses this competition in various ways, including:

- aggressively controlling operating, maintenance, power supply, and fuel costs and passing savings on to customers
- providing renewable energy options and energy waste reduction programs
- providing competitive rate-design options, particularly for large energy-intensive customers
- offering tariff-based incentives that support economic development
- monitoring activity in adjacent geographical areas

Consumers Gas Utility

Gas Utility Operations: Consumers' gas utility operations, which include the purchase, transmission, storage, distribution, and sale of natural gas, generated operating revenue of \$2.5 billion in 2025, \$2.1 billion in 2024, and \$2.4 billion in 2023. Consumers' gas utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigan's Lower Peninsula.

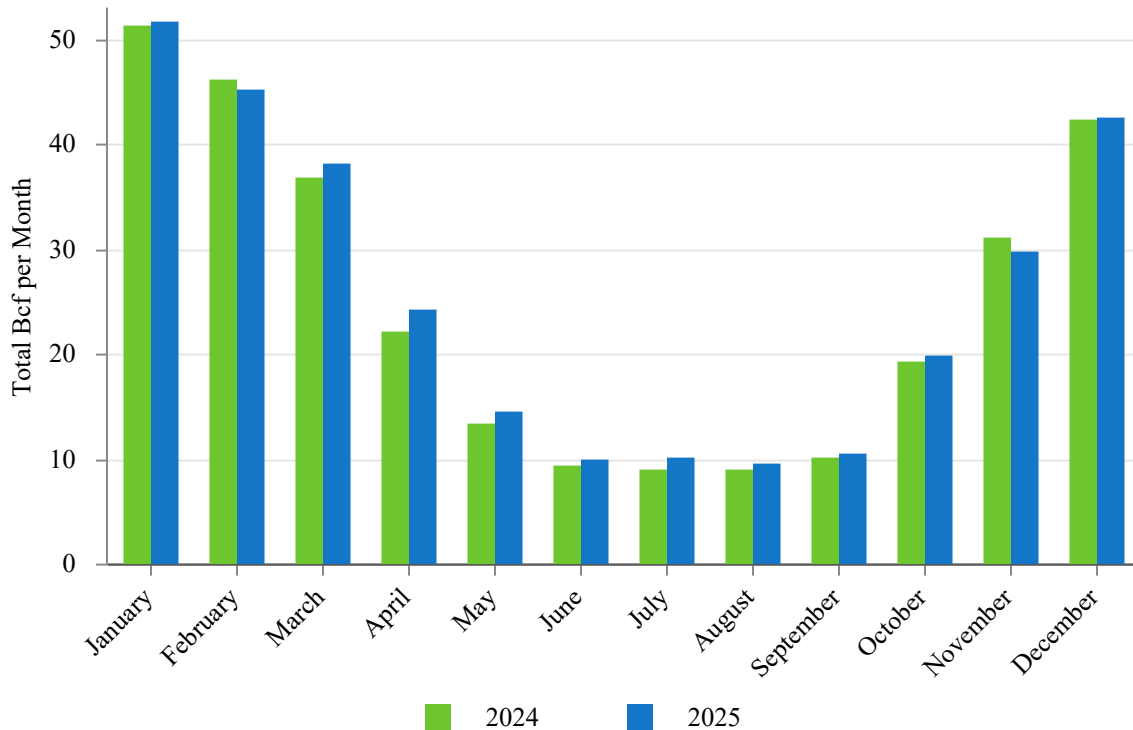
Presented in the following illustration is Consumers' 2025 gas utility operating revenue of \$2.5 billion by customer class:



Consumers' gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers' largest customers is not reasonably likely to have a material adverse effect on Consumers' financial condition.

In 2025, deliveries of natural gas through Consumers' pipeline and distribution network, including off-system transportation deliveries, totaled 396 Bcf, which included GCC deliveries of 31 Bcf. In 2024, deliveries of natural gas through Consumers' pipeline and distribution network, including off-system transportation deliveries, totaled 362 Bcf, which included GCC deliveries of 27 Bcf. Consumers' gas utility operations are seasonal. The consumption of natural gas increases in the winter, due primarily to colder temperatures and the resulting use of natural gas as heating fuel. Consumers injects natural gas into storage during the summer months for use during the winter months. During 2025, 46 percent of the natural gas supplied to all customers during the winter months was supplied from storage.

Presented in the following illustration are Consumers’ monthly weather-normalized natural gas deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including GCC deliveries, during 2025 and 2024:



Gas Utility Properties: Consumers’ gas transmission, storage, and distribution system consists of:

- 2,337 miles of transmission lines
- 14 gas storage fields with a total storage capacity of 300 Bcf and a working gas volume of 153 Bcf
- 28,433 miles of distribution mains
- 8 compressor stations with a total of 147,393 installed and available horsepower

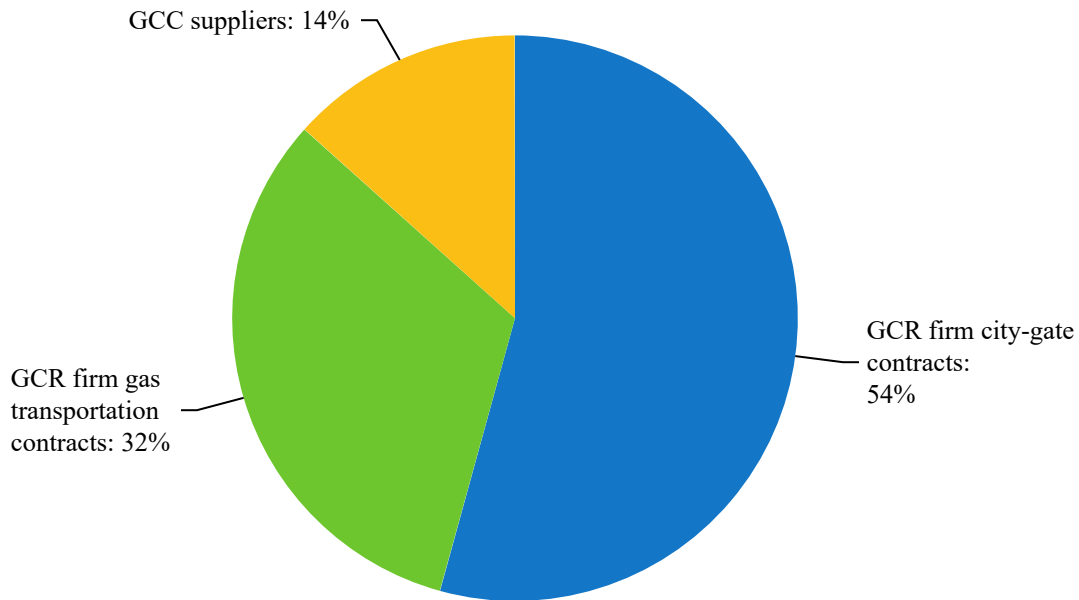
Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers’ Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers, outlines ways in which Consumers can make early progress toward these goals in a cost-effective manner, including energy waste reduction, carbon offsets, and renewable natural gas supply.

Consumers has already initiated work in these key areas by continuing to expand its energy waste reduction targets and by offering gas customers the ability to offset their carbon footprint associated with natural gas use by purchasing renewable natural gas and/or carbon credits associated with Michigan forest preservation. Consumers has renewable natural gas facilities under construction scheduled for commercial operation in 2026 and is monitoring regulatory developments and market conditions closely as part of its ongoing evaluation of the projects. For further information on Consumers’ progress towards its net-zero

methane emissions goal, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview.

Gas Utility Supply: In 2025, Consumers purchased 86 percent of the gas it delivered to its full-service sales customers. The remaining 14 percent was purchased from authorized GCC suppliers and delivered by Consumers to customers in the GCC program. Presented in the following illustration are the supply arrangements for the gas Consumers delivered to GCC and GCR customers during 2025:



Firm city-gate and firm gas transportation contracts are those that define a fixed amount, price, and delivery time frame. Consumers’ firm gas transportation contracts are with Panhandle Eastern Pipe Line Company and Trunkline Gas Company, LLC, each a non-affiliated company. Under these contracts, Consumers purchases and transports gas to Michigan for ultimate delivery to its customers. Consumers’ firm gas transportation contracts expire on various dates through 2028 with planned contract volumes providing 34 percent of Consumers’ total forecasted gas supply requirements for 2026. Consumers purchases the balance of its required gas supply under firm city-gate contracts and through authorized suppliers under the GCC program.

Gas Utility Competition: Competition exists in various aspects of Consumers’ gas utility business. Competition comes from GCC and transportation programs; system bypass by new and existing customers; and from alternative fuels and energy sources, such as propane, oil, and electricity.

NorthStar Clean Energy—Non-utility Operations and Investments

NorthStar Clean Energy, through various subsidiaries and certain equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production. NorthStar Clean Energy's operating revenue was \$408 million in 2025, \$316 million in 2024, and \$297 million in 2023.

Independent Power Production: Presented in the following table is information about the independent power plants in which CMS Energy had an ownership interest at December 31, 2025:

Location	Ownership Interest (%)	Primary Fuel Type	Gross Capacity ¹ (MW)	2025 Net Generation (GWh)
Dearborn, Michigan	100	Natural gas	770	3,965
Jackson County, Arkansas	100	Solar	180	356
Gaylord, Michigan	100	Natural gas	134	22
Comstock, Michigan	100	Natural gas	76	136
Genesee County, Michigan ²	100	Solar	42	1
Alpena, Michigan ³	100	Solar	21	27
Saginaw, Michigan ³	100	Solar	8	10
Paulding County, Ohio	100	Solar and Storage	3	—
Grayling, Michigan ³	100	Solar	1	—
Coke County, Texas	51	Wind	525	1,697
Paulding County, Ohio ⁴	50	Wind	100	299
Filer City, Michigan	50	Coal	73	351
New Bern, North Carolina	50	Wood waste	50	284
Flint, Michigan	50	Wood waste	40	117
Grayling, Michigan	50	Wood waste	38	182
Delta Township, Michigan ⁴	50	Solar	24	38
Total			2,085	7,485

¹ Represents the intended full-load sustained output of each plant. The amount of capacity relating to CMS Energy's ownership interest was 1,665 MW and net generation relating to CMS Energy's ownership interest was 6,018 GWh at December 31, 2025.

² This project began operations in December 2025.

³ Represents a behind-the-meter system located on customer premises.

⁴ NorthStar Clean Energy sold a noncontrolling interest in this plant in 2025. For additional details see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 19, Variable Interest Entities.

The operating revenue from independent power production was \$77 million in 2025, \$69 million in 2024, and \$64 million in 2023.

Energy Resource Management: CMS ERM purchases and sells energy commodities in support of NorthStar Clean Energy's generating facilities with a focus on optimizing the independent power production portfolio. In 2025, CMS ERM marketed 2 Bcf of natural gas and 7,625 GWh of electricity. Electricity marketed by CMS ERM was generated by independent power production of NorthStar Clean

Energy and by unrelated third parties. CMS ERM's operating revenue was \$331 million in 2025, \$247 million in 2024, and \$233 million in 2023.

NorthStar Clean Energy Competition: NorthStar Clean Energy competes with other energy developers, energy retailers, and independent power producers. The needs of this market are driven by current electric demand and available generation, as well as projections of future electric demand and available generation.

CMS Energy and Consumers Regulation

CMS Energy, Consumers, and their subsidiaries are subject to regulation by various federal, state, and local governmental agencies, including those described in the following sections. Rate proceedings and other regulatory actions may affect operations and financial results. If CMS Energy, Consumers, or their subsidiaries failed to comply with applicable laws and regulations, they could become subject to fines, penalties, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. For more information on the potential impacts of government regulation and rate proceedings affecting CMS Energy, Consumers, and their subsidiaries, see Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook, and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

FERC and NERC

CMS Energy and its affiliates and subsidiaries are subject to regulation by FERC in a number of areas. FERC regulates certain aspects of Consumers' electric business, including, but not limited to, compliance with FERC accounting rules, wholesale electric and transmission rates, operation of licensed hydroelectric generating plants, corporate mergers and the sale and purchase of certain assets, issuance of securities, and conduct among affiliates. FERC also regulates the tariff rules and procedures administered by MISO and other independent system operators/regional transmission organizations, including rules governing wholesale electric markets and interconnection of new generating facilities to the transmission system. FERC, in connection with NERC and with regional reliability organizations, also regulates generation and transmission owners and operators, load-serving entities, and others with regard to reliability of the bulk power system.

FERC also regulates limited aspects of Consumers' gas business, principally compliance with FERC capacity release rules, shipping rules, the prohibition of certain buy/sell transactions, and the price-reporting rule.

FERC also regulates holding company matters, interlocking directorates, and other issues affecting CMS Energy. In addition, similar to FERC's regulation of Consumers' electric and gas businesses, FERC has jurisdiction over several independent power plants, PURPA-qualifying facilities, and exempt wholesale generators in which NorthStar Clean Energy has ownership interests, as well as over NorthStar Clean Energy itself, CMS ERM, CMS Gas Transmission, and DIG.

MPSC

Consumers is subject to the jurisdiction of the MPSC, which regulates public utilities in Michigan with respect to retail utility rates, accounting, utility services, certain facilities, certain asset transfers, corporate mergers, and other matters.

The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers. These parties often challenge various aspects of those proceedings, including the prudence of Consumers' policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC and FERC orders.

Other Regulation

The U.S. Secretary of Energy regulates imports and exports of natural gas and has delegated various aspects of this jurisdiction to FERC and the DOE's Office of Fossil Fuels. Additionally, the U.S. Secretary of Energy has the authority to issue emergency orders for power plants under section 202(c) of the Federal Power Act. This provision allows the U.S. Secretary of Energy to temporarily alter the operation of the electricity system during emergencies.

The U.S. Department of Transportation's Office of Pipeline Safety regulates the safety and security of gas pipelines through the Natural Gas Pipeline Safety Act of 1968 and subsequent laws.

The Transportation Security Administration, an agency of the U.S. Department of Homeland Security, regulates certain activities related to the safety and security of natural gas pipelines.

Energy Legislation

In 2023, Michigan enacted the 2023 Energy Law, which among other things:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035; renewable energy generated anywhere within MISO can be applied to meeting this standard, with certain limitations
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- authorized the MPSC to grant extensions of the clean energy or renewable energy standards deadlines if compliance is not practically feasible, would be excessively costly to customers, or would cause reliability issues
- increased the energy waste reduction requirement for electric utilities to achieve annual reductions in customers' electricity use from the present 1-percent reduction requirement to 1.5 percent beginning in 2026; beyond this requirement, the law set a goal of a 2-percent reduction and required that such goal be incorporated in an electric utility's integrated resource plan modeling scenarios
- increased the energy waste reduction requirement for gas utilities to achieve annual reductions in customers' gas use from the present 0.75-percent reduction requirement to 0.875 percent beginning in 2026
- enhanced existing incentives for energy efficiency programs and returns earned on new clean or renewable PPAs
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW
- expanded the statutory cap on distributed generation resources to 10 percent of the electric utility's five-year average peak load
- expanded the MPSC's scope of considerations in integrated resource plans to include affordability, greenhouse gas emissions, environmental justice considerations, the effects on human health, and other environmental concerns
- provided the MPSC siting authority over large renewable energy projects

Consumers' updates to its Renewable Energy Plan, which were approved by the MPSC in September 2025, and planned updates to its integrated resource plan in 2026 will serve as a blueprint to meeting the requirements of the 2023 Energy Law by focusing on increasing the generation of renewable energy, deploying energy storage, helping customers use less energy, and offering demand response programs to reduce demand during critical peak times.

CMS Energy and Consumers Environmental Strategy and Compliance

CMS Energy and Consumers are committed to protecting the environment; this commitment extends beyond compliance with applicable laws and regulations. Consumers' Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers' Renewable Energy Plan. The Electric Supply Plan is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives. This plan positions Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040.

Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. For additional information on Consumers' Methane Reduction Plan, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Gas Utility Outlook and Uncertainties—Gas Environmental Outlook.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers expects to meet this goal through carbon offset measures, renewable natural gas, energy efficiency and demand response programs, and the adoption of cost-effective emerging technologies once proven and commercially available.

CMS Energy's and Consumers' commitment to protecting the environment extends to advancing the principles of environmental justice in current and future operations. These principles center on protecting communities impacted by the companies' operations, especially those communities that are most vulnerable and may have suffered disparate impacts of environmental harm.

Advancing environmental justice comes in a variety of forms. For example, Consumers has conducted an environmental justice analysis to help understand the environmental impacts of its clean energy transformation. Similarly, Consumers is using an environmental justice screening tool provided by the State of Michigan in the planning of improvements to the electric and gas distribution system, including prioritizing investments in more vulnerable communities.

A core tenet of environmental justice is inviting the input of the stakeholders in the local communities where CMS Energy and Consumers operate and invest. The companies are committed to maintaining a transparent dialogue when developing projects, whether in new or existing areas of operation.

CMS Energy, Consumers, and their subsidiaries are subject to various federal, state, and local environmental regulations for solid waste management, air and water quality, and other matters. Consumers expects to recover costs to comply with environmental regulations in customer rates but cannot guarantee this result. For additional information concerning environmental matters, see Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of

Operations—Outlook, and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

CMS Energy has recorded a \$48 million liability for its subsidiaries' obligations associated with Bay Harbor and Consumers has recorded a \$59 million liability for its obligations at a number of former MGP sites. For additional information, see Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

Costs related to the construction, operation, corrective action, and closure of solid waste disposal facilities for coal ash are significant. Consumers' coal ash disposal areas are regulated under Michigan's solid waste rules and by the EPA's rules regulating CCRs. To address some of the requirements of these rules, Consumers has converted all of its fly ash handling systems to dry conveyance systems. In addition, Consumers' ash facilities have programs designed to protect the environment and are subject to quarterly EGLE inspections. Consumers' estimate of capital and cost of removal expenditures to comply with regulations relating to ash disposal is \$241 million from 2026 through 2030. Consumers' future costs to comply with solid waste disposal regulations may vary depending on future legislation, litigation, executive orders, treaties, or rulemaking. These costs may further increase if additional emergency orders necessitate continued operation of the J.H. Campbell plant beyond current expectations. Consumers intends to request recovery of any incremental costs through its ongoing cases before FERC. For additional information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

For further information concerning estimated capital expenditures related to environmental matters, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

Insurance

CMS Energy and its subsidiaries, including Consumers, maintain insurance coverage generally similar to comparable companies in the same lines of business. The insurance policies are subject to terms, conditions, limitations, and exclusions that might not fully compensate CMS Energy or Consumers for all losses. A portion of each loss is generally assumed by CMS Energy or Consumers in the form of deductibles and self-insured retentions that, in some cases, are substantial. As CMS Energy or Consumers renews its policies, it is possible that some of the present insurance coverage may not be renewed or obtainable on commercially reasonable terms due to restrictive insurance markets.

Human Capital

CMS Energy and Consumers employ a highly trained and skilled workforce comprised of union and non-union employees. Presented in the following table are the number of employees of CMS Energy and Consumers:

December 31	2025	2024	2023
CMS Energy, including Consumers			
Full-time and part-time employees	8,350	8,324	8,356
Consumers			
Full-time and part-time employees	8,095	8,090	8,144

At December 31, 2025, unions represented 44 percent of CMS Energy’s employees and 45 percent of Consumers’ employees. The UWUA represents Consumers’ and NorthStar Clean Energy’s operating, maintenance, construction employees and Consumers’ customer contact center employees. The USW represents Consumers’ Zeeland plant employees. Consumers’ union agreements expire in 2030 and the majority of NorthStar Clean Energy’s represented employees have an agreement that expires in 2029.

The safety of co-workers, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions. On an annual basis, CMS Energy and Consumers set various safety goals tied to the OSHA recordable incident rate and to high-risk injuries. The companies’ OSHA recordable incident rate was 2.34 in 2025 and 1.71 in 2024. High-risk injuries encompass all recordable and non-recordable incidents with the potential for serious injury or fatality. In 2025, the companies recorded nine high-risk injuries, achieving their goal of less than 12 high-risk injuries. Beginning in 2026, the companies will utilize the serious injury incidence rate to measure and set safety goals. The target serious injury incidence rate for 2026 is 0.037, which, if achieved, would place Consumers within the second quartile of its EEI peer group.

Within the utility industry, there is strong competition for rare, high-demand talent, including those related to electric line work, renewable energy generation, technology, and data analytics. In order to address this competition and to be able to meet their human capital needs, CMS Energy and Consumers provide compensation and benefits that are competitive with industry peers. Furthermore, CMS Energy and Consumers have developed a comprehensive talent strategy, the People Strategy, to attract, develop, and retain highly skilled co-workers. The strategy focuses on three areas, which are summarized below. The first two areas listed below focus on creating an environment that attracts and retains top talent and ensuring that all co-workers can thrive and contribute to the companies’ mission and purpose.

- **Cultivating a Purpose-driven Culture:** This goal aims to ensure all co-workers understand how their work contributes to CMS Energy’s and Consumers’ key strategic goals.
- **Creating a Breakthrough Employee Experience:** A breakthrough employee experience is one that instills pride and ownership in one’s work. To measure progress toward a breakthrough employee experience, CMS Energy and Consumers assess engagement, empowerment, and

diversity, equity, and inclusion efforts using the companies’ culture index. For the year ended December 31, 2025, the companies attained scores of:

- 75-percent positive sentiment for engagement, up 3 percentage points from 2024
- 65-percent positive sentiment for empowerment, no change from 2024
- 75-percent positive sentiment for diversity, equity, and inclusion, up 2 percentage points from 2024

CMS Energy and Consumers aim to continuously improve these scores every year.

- **Building Skill Sets at Scale:** With an overarching goal of ensuring co-workers have the right skills to succeed, CMS Energy and Consumers measure progress in this area through achievement of workforce planning and hiring milestones and through a first-time skill attainment index to evaluate the effectiveness of training. CMS Energy and Consumers develop skill sets in co-workers through a variety of means, including union apprenticeship programs and yearly trainings for newly required skills.

This talent strategy allows CMS Energy and Consumers to shape co-workers’ experience and enable leaders to coach and develop co-workers, source talent, and anticipate and adjust to changing skill sets in the business environment.

Diversity, Equity, and Inclusion

As a part of their People Strategy, CMS Energy and Consumers employ a broad and holistic diversity, equity, and inclusion strategy focused on embracing differences and creating a sense of belonging for all co-workers. The strategy is aimed at integrating principles of equity and inclusion into every process and co-worker experience. To measure their success, CMS Energy and Consumers utilize select questions in the annual engagement survey to create a diversity, equity, and inclusion index. For the year ended December 31, 2025, the diversity, equity, and inclusion index score was 75 percent.

CMS Energy and Consumers are committed to building an inclusive workplace that embraces the diverse makeup of the communities that they serve. The following table presents the composition of CMS Energy’s and Consumers’ workforce:

December 31, 2025	CMS Energy, including Consumers	Consumers
Percent female employees	26 %	26 %
Percent racially or ethnically diverse employees	13	13
Percent employees with disabilities	5	5
Percent veteran employees	10	10

Co-workers are also empowered to engage in business employee resource groups and events that encourage candid conversations around diversity, equity, and inclusion. These activities enhance personal growth, build stronger connections among co-workers, and contribute to a more inclusive workplace. There are eight business employee resource groups available to all co-workers; these groups are:

- Women in Energy, working toward an inclusive place for all women in the fields they have chosen, from front line to management
- the Minority Advisory Panel, promoting a culture of diversity and inclusion among all racial and ethnic minorities through education, leadership, development, and networking
- the Veterans Advisory Panel, supporting former and active military personnel and assisting in recruiting and retaining veterans through career development
- Genergy, a multigenerational group designed to bridge the gap of learning, networking, and mentoring across the generations of the workforce
- the Pride Alliance of CMS Energy, promoting an inclusive environment that is safe, supportive, and respectful for lesbian, gay, bi-sexual, and transgender persons and allies
- Capable, aimed at removing barriers and creating pathways to meaningful work for co-workers of all abilities
- Interfaith, a space for co-workers of all backgrounds to gather and celebrate their unique beliefs, creating an environment of understanding and respect for all faiths, religions, and spiritual beliefs, including those with no faith affiliation
- People and Planet Partners, empowering co-workers to drive social benefits for customers and communities and advance environmental improvements, reduce the companies' environmental footprint, and support the companies' planet goals

Information About CMS Energy’s and Consumers’ Executive Officers

Presented in the following table are the company positions held during the last five years for each of CMS Energy’s and Consumers’ executive officers as of February 10, 2026:

Name, Age, Position(s)	Period
Garrick J. Rochow (age 51)	
<i>CMS Energy</i>	
President, CEO, and Director	12/2020 – Present
<i>Consumers</i>	
President, CEO, and Director	12/2020 – Present
<i>NorthStar Clean Energy</i>	
Chairman of the Board, CEO, and Director	12/2020 – 7/2025
Rejji P. Hayes (age 51)	
<i>CMS Energy</i>	
Executive Vice President and CFO	5/2017 – Present
<i>Consumers</i>	
Executive Vice President and CFO	5/2017 – Present
<i>NorthStar Clean Energy</i>	
Chairman of the Board and Director	7/2025 – Present
Executive Vice President, CFO, and Director	5/2017 – 6/2024
<i>EnerBank</i>	
Chairman of the Board and Director	10/2018 – 10/2021
Tonya L. Berry (age 53)	
<i>CMS Energy</i>	
Executive Vice President and Chief Operating Officer	7/2025 – Present
Senior Vice President	2/2022 – 7/2025
<i>Consumers</i>	
Executive Vice President and Chief Operating Officer	7/2025 – Present
Senior Vice President	2/2022 – 7/2025
Vice President	11/2018 – 2/2022
Shaun M. Johnson (age 47)	
<i>CMS Energy</i>	
Executive Vice President and Chief Legal and Administrative Officer	7/2025 – Present
Senior Vice President and General Counsel	5/2019 – 7/2025
<i>Consumers</i>	
Executive Vice President and Chief Legal and Administrative Officer	7/2025 – Present
Senior Vice President and General Counsel	5/2019 – 7/2025
<i>NorthStar Clean Energy</i>	
Senior Vice President, General Counsel, and Director	4/2019 – 6/2024

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Name, Age, Position(s)	Period
Brandon J. Hofmeister (age 49)	
<i>CMS Energy</i>	
Senior Vice President	7/2017 – Present
<i>Consumers</i>	
Senior Vice President	7/2017 – Present
<i>NorthStar Clean Energy</i>	
Senior Vice President	9/2017 – 6/2024
Lauren Snyder (age 44)	
<i>CMS Energy</i>	
Senior Vice President and Chief Customer and Growth Officer	7/2025 – Present
<i>Consumers</i>	
Senior Vice President and Chief Customer and Growth Officer	7/2025 – Present
Vice President	7/2017 – 7/2025
Scott B. McIntosh (age 50)	
<i>CMS Energy</i>	
Vice President, Controller, and CAO	9/2021 – Present
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021
<i>Consumers</i>	
Vice President, Controller, and CAO	9/2021 – Present
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021
<i>NorthStar Clean Energy</i>	
Vice President, CAO, and Director	6/2024 – Present
Vice President, Controller, and CAO	9/2021 – 6/2024
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021

There are no family relationships among executive officers and directors of CMS Energy or Consumers. The list of directors and their biographies will be included in CMS Energy’s and Consumers’ definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The term of office of each of the executive officers extends to the first meeting of the Board after the next annual election of Directors of CMS Energy and Consumers (to be held on May 8, 2026).

Available Information

CMS Energy's internet address is www.cmsenergy.com. CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution for material information. Information contained on CMS Energy's website is not incorporated herein. CMS Energy's and Consumers' annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act are accessible free of charge on CMS Energy's website. These reports are available soon after they are electronically filed with the SEC. Also on CMS Energy's website are CMS Energy's and Consumers':

- Corporate Governance Principles
- Articles of Incorporation
- Bylaws
- Charters and Codes of Conduct (including the Charters of the Audit Committee, Compensation and Human Resources Committee, Finance Committee, and Governance, Sustainability and Public Responsibility Committee, as well as the Employee, the Board, and Third Party Codes of Conduct)

CMS Energy will provide this information in print to any stockholder who requests it.

The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address is www.sec.gov.

Item 1A. Risk Factors

CMS Energy and Consumers are exposed to a variety of factors, often beyond their control, that are difficult to predict and that involve uncertainties that may materially adversely affect CMS Energy's or Consumers' business, liquidity, financial condition, or results of operations. Additional risks and uncertainties not presently known or that management believes to be immaterial may also adversely affect CMS Energy or Consumers. The risk factors described in the following sections, as well as the other information included in this report and in other documents filed with the SEC, should be considered carefully before making an investment in securities of CMS Energy or Consumers. Risk factors of Consumers are also risk factors of CMS Energy.

Investment/Financial Risks

CMS Energy depends on dividends from its subsidiaries to meet its debt service obligations.

Due to its holding company structure, CMS Energy depends on dividends from its subsidiaries to meet its debt service and other payment obligations. If sufficient dividends were not paid to CMS Energy by its subsidiaries, CMS Energy might not be able to generate the funds necessary to fulfill its payment obligations.

Consumers' ability to pay dividends or acquire its own stock from CMS Energy is limited by restrictions contained in Consumers' preferred stock provisions and potentially by other legal restrictions, such as certain terms in its articles of incorporation and FERC requirements.

CMS Energy has indebtedness that could limit its financial flexibility and its ability to meet its debt service obligations.

The level of CMS Energy's present and future indebtedness could have several important effects on its future operations, including, among others, that:

- a significant portion of CMS Energy's cash flow from operations could be dedicated to the payment of principal and interest on its indebtedness and would not be available for other purposes
- covenants contained in CMS Energy's existing debt arrangements, which require it to meet certain financial tests, could affect its flexibility in planning for, and reacting to, changes in its business
- CMS Energy's ability to obtain additional financing for working capital, capital expenditures, acquisitions, and general corporate and other purposes could become limited
- CMS Energy could be placed at a competitive disadvantage to its competitors that are less leveraged
- CMS Energy's vulnerability to adverse economic and industry conditions could increase
- CMS Energy's future credit ratings could fluctuate

CMS Energy's ability to meet its debt service obligations and to reduce its total indebtedness will depend on its future performance, which will be subject to general economic conditions, industry cycles, changes in laws or regulatory decisions, and financial, business, and other factors affecting its operations, many of which are beyond its control. CMS Energy cannot make assurances that its businesses will continue to generate sufficient cash flow from operations to service its indebtedness, which could require CMS Energy to sell assets or obtain additional financing.

CMS Energy and Consumers have financing needs and could be unable to obtain bank financing or access the capital markets.

CMS Energy and Consumers rely on the capital markets, as well as on bank syndications, to meet their financial commitments and short-term liquidity needs not otherwise funded internally.

Disruptions in the capital and credit markets, or the inability to obtain required regulatory authorization for issuances of securities including debt, including as may be required from FERC, could adversely affect CMS Energy's and Consumers' access to liquidity needed for their businesses. Any liquidity disruption could require CMS Energy and Consumers to take measures to conserve cash including, but not limited to, deferring capital expenditures, changing commodity purchasing strategies to avoid collateral-posting requirements, and reducing or eliminating future share repurchases, dividend payments, or other discretionary uses of cash.

Entering into new financings is subject in part to capital market receptivity to utility industry securities in general and to CMS Energy's and Consumers' securities in particular. CMS Energy and Consumers continue to explore financing opportunities to supplement their respective financial strategies. These potential opportunities include refinancing and/or issuing new debt, issuing CMS Energy preferred stock and/or common equity, or entering into commercial paper, bank financing, and leasing arrangements. CMS Energy and Consumers cannot guarantee the capital markets' acceptance of their securities. CMS Energy and Consumers may also, from time to time, repurchase (either in open market transactions or through privately negotiated transactions), redeem, or otherwise retire outstanding debt. Such activities, if any, will depend on prevailing market conditions, contractual restrictions, and other factors. The amounts involved may or may not be material.

Certain of CMS Energy's and Consumers' securities and those of their affiliates are rated by various credit rating agencies. A reduction or withdrawal of one or more of its credit ratings could have a material adverse impact on CMS Energy's or Consumers' ability to access capital on acceptable terms and maintain commodity lines of credit, could increase their cost of borrowing, and could cause CMS Energy or Consumers to reduce capital expenditures. If either or both were unable to maintain commodity lines of credit, CMS Energy or Consumers might have to post collateral or make prepayments to certain suppliers under existing contracts. Further, since Consumers provides dividends to CMS Energy, any adverse developments affecting Consumers that result in a lowering of its credit ratings could have an adverse effect on CMS Energy's credit ratings.

Market performance and other changes could decrease the value of employee benefit plan assets, which then could require substantial funding.

The performance of various markets affects the value of assets that are held in trust to satisfy future obligations under CMS Energy's and Consumers' pension and postretirement benefit plans. CMS Energy and Consumers have significant obligations under these plans and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which could fall below CMS Energy's and Consumers' forecasted return rates. A decline in the market value of the assets or a change in the level of interest rates used to measure the required minimum funding levels could significantly increase the funding requirements of these obligations. Also, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, could significantly increase the funding requirements of the obligations related to the pension and postretirement benefit plans.

Industry/Regulatory Risks

Changes to ROA could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers' sales, with certain exceptions. The proportion of Consumers' electric deliveries under the ROA program and on the ROA waiting list is over 10 percent. Consumers' rates are regulated by the MPSC, while alternative electric suppliers charge market-based rates, putting competitive pressure on Consumers' electric supply. Groups are advocating for an ROA-like community solar program that allows third parties to sell directly to customers and offer them a regulated bill credit. If the amount of ROA sales increased, this new ROA-like community solar program were allowed, or electric generation service in Michigan were further deregulated, it could have a material adverse effect on CMS Energy and Consumers.

FERC issued an advance notice of proposed rulemaking in response to the Secretary of the DOE's direction to FERC to consider the advance notice of proposed rulemaking as a means to standardize and expedite interconnection procedures and agreements for large electric loads. If FERC asserts jurisdiction over the distribution components of large-load customers' interconnections to the transmission system, or allows large-load customers to directly purchase electricity from wholesale markets, it could have a material adverse effect on CMS Energy and Consumers.

The creation of utilities by municipalities in Consumers' service territory, or the impairment of Consumers' franchise rights to serve customers in municipalities, could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows Consumers' electric and natural gas utility businesses to serve customers pursuant to franchises granted by municipalities. Michigan law also allows municipalities to create, own, and operate

utilities. If one or more municipalities in Consumers' service territory created a new or supplemental utility, or impaired the franchise under which Consumers serves customers in the municipality, it could have a material adverse effect on CMS Energy and Consumers.

Distributed energy resources could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows customers to use distributed energy resources for their electric energy needs. These distributed energy resources are connected to Consumers' electric grid. The 2023 Energy Law increases the cap on Consumers' distributed generation program to 10 percent of utilities' peak loads. It also specifies an inflow and outflow rate method that must be implemented by the MPSC. FERC policy allows many customer-owned behind-the-meter and grid-connected distributed energy resources to participate in and receive revenue from wholesale electricity markets, as governed by evolving wholesale market rules subject to FERC oversight. Increased customer use of distributed energy resources could result in a reduction of Consumers' electric sales. Third parties' operations of distributed energy resources could also potentially have a negative impact on the stability of the grid. An increase in customers' use of distributed energy resources, and the rate structure for distributed energy resources customers' use of Consumers' system and Consumers' purchases of their excess generation, could have a material adverse effect on CMS Energy and Consumers.

CMS Energy and Consumers are subject to rate regulation, which could have a material adverse effect on financial results.

CMS Energy and Consumers are subject to rate regulation. Consumers' electric and gas retail rates are set by the MPSC and cannot be changed without regulatory authorization. If rate regulators fail to provide adequate rate relief, it could have a material adverse effect on Consumers or Consumers' plans for making significant capital investments. Additionally, increasing rates could result in additional regulatory scrutiny, regulatory or legislative actions, and increased competitive or political pressures, all of which could have a material adverse effect on CMS Energy's and Consumers' liquidity, financial condition, and results of operations.

Orders of the MPSC could limit recovery of costs of providing service. These orders could also result in adverse regulatory treatment of other matters. For example, MPSC orders could prevent or curtail Consumers from shutting off non-paying customers, could prevent or limit the implementation of an electric or gas revenue mechanism, or could penalize Consumers for not meeting service and reliability standards. Regulators could face competitive or political pressures to avoid or limit rate increases for a number of reasons, including affordability concerns, economic downturn, reliability and economic justice concerns, or decreased customer base, among others.

FERC authorizes certain subsidiaries of CMS Energy, including Consumers, to sell wholesale electricity at market-based rates and to provide certain other wholesale electric services at rates and terms subject to FERC approval. Failure of these subsidiaries to maintain this FERC authority could have a material adverse effect on CMS Energy's and Consumers' liquidity, financial condition, and results of operations. Electric transmission and natural gas pipeline rates paid by Consumers and other CMS Energy subsidiaries are also set by FERC, as are the tariff terms governing the participation of Consumers and other CMS Energy subsidiaries in FERC-regulated wholesale electricity markets operated by regional transmission organizations and independent system operators such as MISO and PJM. At least one CMS Energy subsidiary participates in the wholesale electricity markets operated by ERCOT, over which FERC has limited control.

Consumers also faces regulatory uncertainty resulting from the U.S. Secretary of Energy's emergency orders issued under the Federal Power Act and associated DOE regulations, which direct continued

operation of the J.H. Campbell, as well as similar prior or future executive actions, including the January 2025 and April 2025 executive orders related to energy supply and reliability. The Federal Power Act, DOE regulations, and U.S. Secretary of Energy emergency orders all provide for cost recovery associated with continued operations, but there is not currently a FERC-approved MISO Tariff for recovery of compliance costs associated with the continued operation of J.H. Campbell, and continued operation of J.H. Campbell is not contemplated in Consumers' current MPSC rates or rate filings at the MPSC. Consumers is pursuing cost recovery at FERC but cannot predict the outcome of those efforts or the impact of other executive actions.

The various risks associated with the MPSC and FERC regulation of CMS Energy's and Consumers' businesses, which include the risk of adverse decisions in any number of rate or regulatory proceedings before either agency, as well as judicial proceedings challenging any agency decisions, could have a material adverse effect on CMS Energy and Consumers. Changes to the tariffs or business practice manuals of certain wholesale market operators such as MISO, PJM, or ERCOT, or corresponding impacts such as interconnection delays for new electric generation or storage projects, could also have a material adverse effect on CMS Energy and Consumers.

Utility regulation, state or federal legislation, regulation, and compliance could have a material adverse effect on CMS Energy's and Consumers' businesses.

CMS Energy and certain of its subsidiaries, including Consumers, are subject to, or affected by, extensive utility regulation and state and federal legislation and regulation, including through application of policies and rules of numerous state and federal agencies and governmental entities. If it were determined that CMS Energy or Consumers failed to comply with applicable laws and regulations or with applicable tariff provisions, they could become subject to fines, penalties, refund or disgorgement orders, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. CMS Energy and Consumers cannot predict the impact of new laws, rules, regulations, tariffs, principles, orders, or practices by federal or state agencies or wholesale electricity market operators, or challenges or changes to present laws, rules, regulations, tariffs, principles, orders, or practices and the interpretation of any adoption or change. Furthermore, any state or federal legislation, regulation, order, or other action concerning CMS Energy's or Consumers' operations could also have a material adverse effect.

FERC, through NERC and its delegated regional entities, oversees reliability of certain portions of the electric grid. CMS Energy and Consumers cannot predict the impact of the DOE or FERC orders or actions of NERC and its regional entities on electric system reliability. Additionally, natural gas pipeline infrastructure has recently been under scrutiny following disruptions related to extreme weather and cyber incidents. Additional regulation in this area could adversely affect Consumers' gas operations.

CMS Energy and Consumers have announced ambitious plans to reduce their impact on climate change and increase the reliability of their electric distribution system. Achieving these plans depends on numerous factors, many of which are outside of their control.

Consumers has announced a long-term strategy for delivering clean, reliable, resilient, and affordable energy, and other subsidiaries of CMS Energy have plans to develop and operate clean energy assets. The MPSC, FERC, other regulatory authorities, or other third parties may prohibit, delay, or impair some or all of CMS Energy's and Consumers' planned acquisitions or development of owned or purchased electric generation and storage capacity. Consumers' planned electric generation capacity, including renewable generation or storage projects, may be adversely impacted by interconnection delays at MISO or in the footprints of other regional transmission organizations, and/or by interconnection costs. CMS Energy and Consumers and its contractors may be unable to acquire, site, construct timely, and/or permit generation and storage capacity, including some or all of the generation and storage capacity

proposed in Consumers' plan. CMS Energy and Consumers' ability to implement their plans may be affected by environmental regulations, global supply chain disruptions, import tariffs, and changes in the cost, availability, and supply of generation and storage capacity. While CMS Energy and Consumers continue to advocate for advances in commercially available technologies required to reduce or eliminate greenhouse gases on a cost-effective basis at scale, such advances are largely outside of CMS Energy's and Consumers' control. Advancements in technology related to items such as battery storage, carbon capture/storage, and electric vehicles may not become commercially available or economically feasible as projected. Customer programs such as energy efficiency and demand response may not realize the projected levels of customer participation.

Consumers has also announced its electric Reliability Roadmap. The Reliability Roadmap includes larger investments in grid hardening, distribution capacity, and automation to deliver better than median reliability to customers given increasingly severe weather and customer adoption of new technologies. The MPSC or other third parties may prohibit, delay, or impair the Reliability Roadmap and some or all of the associated capital investments. Consumers' ability to implement its plan may be affected by global supply chain disruptions and/or workforce availability.

Consumers has also announced its Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers. This plan includes accelerated infrastructure replacements, innovative leak detection technology, and process changes to reduce or eliminate methane emissions. The MPSC, FERC, U.S. Department of Transportation, other regulatory authorities, or other third parties may prohibit, delay, or impair the Natural Gas Delivery Plan and some or all of the associated capital investments. Consumers' ability to implement its plan may be affected by environmental regulations, global supply chain disruptions, import tariffs, and changes in the cost, availability, and supply of natural gas or the ability to deliver natural gas to customers. Advancements in technology related to items such as renewable natural gas may not become commercially available or economically feasible as projected in Consumers' plan.

CMS Energy and Consumers could suffer financial loss, reputational damage, litigation, or other negative repercussions if they are unable to achieve their ambitious plans.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact CMS Energy and Consumers.

CMS Energy and Consumers are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate their obligations to taxing authorities. The tax obligations include income taxes, real estate taxes, sales and use taxes, employment-related taxes, and ongoing issues related to these tax matters. The judgments include determining reserves for potential adverse outcomes regarding tax positions that have been taken and may be subject to challenge by the IRS and/or other taxing authorities. Unfavorable settlements of any of the issues related to these reserves or other tax matters at CMS Energy or Consumers could have a material adverse effect. Additionally, changes in federal, state, or local tax rates or other changes in tax laws could have adverse impacts. In July 2025, President Trump signed the OBBBA into law. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

CMS Energy and its subsidiaries, including Consumers, must comply with the Dodd-Frank Act and its related regulations.

The Dodd-Frank Act provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although CMS Energy, Consumers, and certain subsidiaries of NorthStar Clean Energy qualify for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of these entities to participate in these markets and could add additional regulatory oversight over their contracting activities.

CMS Energy and Consumers could incur substantial costs to comply with environmental requirements.

CMS Energy and Consumers are subject to costly and stringent environmental regulations that may require additional significant capital expenditures for CCR disposal and storage, emission reductions, and PCB remediation. In addition, regulatory action on PFAS at the state and/or federal level could cause CMS Energy and Consumers to further test and remediate some sites if PFAS is present at certain levels. Present and reasonably anticipated state and federal environmental statutes and regulations will continue to have a material effect on CMS Energy and Consumers.

CMS Energy and Consumers have interests in fossil-fuel-fired power plants, other types of power plants, and natural gas systems that emit greenhouse gases. Federal, state, and local environmental laws, regulations and orders, as well as international accords and treaties, could require CMS Energy and Consumers to install additional equipment for emission controls, undertake heat-rate improvement projects, purchase carbon emissions allowances, curtail or extend operations, invest in generating capacity with fewer carbon dioxide emissions, or take other significant steps to manage or lower the emission of greenhouse gases. Similarly, Consumers could be restricted from constructing natural gas infrastructure due to potential environmental regulations, which could require more costly alternatives.

The following risks related to climate change, emissions, and environmental regulations could also have a material adverse impact on CMS Energy and Consumers:

- a change in policy/regulation, regulators' implementation of policy/regulation or litigation originated by third parties against CMS Energy or Consumers due to CMS Energy's or Consumers' greenhouse gas or other emissions or CCR disposal and storage
- impairment of CMS Energy's or Consumers' reputation due to their greenhouse gas or other emissions and public perception of their response to potential environmental regulations, rules, orders, and legislation
- weather that may affect customer demand, company operations, or company infrastructure, including catastrophic weather-related damage and extreme temperatures; natural disasters such as severe storms, floods, and droughts; fires; or smoke
- implementation of state or federal environmental justice requirements

Consumers expects to collect fully from its customers, through the ratemaking process, expenditures incurred to comply with environmental regulations, but cannot guarantee this outcome. There is not currently a FERC-approved MISO Tariff for recovery of compliance costs associated with the continued operation of J.H. Campbell, and continued operation of J.H. Campbell is not contemplated in Consumers' current MPSC rates or rate filings at the MPSC. Consumers is pursuing cost recovery at FERC but cannot predict the outcome of those efforts or the impact of other executive actions. If Consumers were unable to recover these expenditures from customers in rates, CMS Energy or Consumers could be required to seek significant additional financing to fund these expenditures.

For additional information regarding compliance with environmental regulations, see Item 1. Business—CMS Energy and Consumers Environmental Strategy and Compliance and Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook.

CMS Energy’s and Consumers’ businesses could be affected adversely by any delay in meeting environmental requirements.

A delay or failure by CMS Energy or Consumers to obtain or maintain any necessary environmental permits or approvals to satisfy any applicable environmental regulatory requirements or install emission or pollution control equipment could:

- prevent the construction of new facilities
- prevent the continued operation of and sale of energy from existing facilities
- modify the way in which a facility is operated
- prevent the suspension of operations at existing facilities
- prevent the modification of existing facilities
- result in significant additional costs, including fines or penalties

CMS Energy and Consumers expect to incur additional substantial costs related to environmental remediation of former sites.

Consumers expects to incur additional substantial costs related to the remediation of its former MGP sites and other response activity costs at a number of other former sites, including, but not limited to, sites of retired coal-fueled electric generating units and sites containing coal ash and related materials, under NREPA, RCRA, CERCLA and related state and federal regulations. Consumers believes these costs should be recoverable in rates but cannot guarantee that outcome.

Business/Operations Risks

There are risks associated with Consumers’ substantial capital investment program planned for the next five years.

Consumers’ planned investments include the construction or acquisition of electric generation, electric and gas infrastructure, conversions and expansions, environmental controls, electric grid automation technologies, and other electric and gas investments to upgrade delivery systems, as well as decommissioning of older facilities. The success of these capital investments depends on or could be affected by a variety of factors that include, but are not limited to:

- effective pre-acquisition evaluation of asset values, future operating costs, potential environmental and other liabilities, and other factors beyond Consumers’ control
- effective cost and schedule management of new capital projects
- availability of qualified construction personnel, both internal and contracted
- effective and timely contractor performance
- changes in commodity and other prices, applicable tariffs, and/or material and equipment availability
- governmental actions
- interconnection uncertainty, delays, and costs for electric generation projects

- operational performance
- changes in environmental, legislative, and regulatory requirements
- regulatory cost recovery
- inflation of labor rates and material and equipment prices
- supply chain disruptions and increased lead times
- barriers to accessing key materials for renewable projects (solar, battery, and other key equipment) created by geopolitical relations

It is possible that adverse events associated with these factors could have a material adverse effect on Consumers.

CMS Energy and Consumers could be affected adversely by legacy litigation and retained liabilities.

The agreements that CMS Energy and Consumers enter into for the sale of assets can include provisions whereby they are required to:

- retain specified preexisting liabilities, such as for taxes, pensions, or environmental conditions
- indemnify the buyers against specified risks, including the inaccuracy of representations and warranties that CMS Energy and Consumers make
- make payments to the buyers depending on the outcome of post-closing adjustments, litigation, audits, or other reviews, including claims resulting from attempts by foreign or domestic governments to assess taxes on past operations or transactions

Many of these contingent liabilities can remain open for extended periods of time after the sales are closed. Depending on the extent to which the buyers might ultimately seek to enforce their rights under these contractual provisions, and the resolution of any disputes concerning them, there could be a material adverse effect on CMS Energy's or Consumers' liquidity, financial condition, and results of operations.

Consumers is exposed to risks related to general economic conditions in its service territories.

Consumers' electric and gas utility businesses are affected by the economic conditions impacting the customers they serve. If the Michigan economy becomes sluggish or declines, Consumers could experience reduced demand for electricity or natural gas that could result in decreased earnings and cash flow. In addition, economic conditions in Consumers' service territory affect its collections of accounts receivable and levels of lost or stolen gas.

Consumers is exposed to changes in customer usage that could impact financial results.

Technology advances, government incentives and subsidies, and regulatory decisions could increase the cost effectiveness of customer-owned methods of producing electricity and managing energy use resulting in reduced load, cross subsidization, and increased costs.

Customers could also reduce their consumption of electricity and natural gas through energy waste reduction programs. Similarly, customers could also reduce their consumption of natural gas through alternative technologies or fuels or through electrification.

CMS Energy's and Consumers' energy sales and operations are affected by seasonal factors and varying weather conditions from year to year.

CMS Energy's and Consumers' utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment, while peak demand for natural gas occurs in the winter due to colder temperatures and the

resulting use of natural gas as heating fuel. Accordingly, CMS Energy's and Consumers' overall results may fluctuate substantially on a seasonal basis. Mild temperatures during the summer cooling season and winter heating season as well as the impact of extreme weather events on Consumers' system could have a material adverse effect.

Demand for electricity associated with data center expansion could have a material effect on CMS Energy and Consumers.

Consumers' utility operations are affected by new customers and load growth. Rapid expansion of data centers associated with increasing demand for cloud services, artificial intelligence, and other applications could lead to an unprecedented increase in demand for electric power in MISO and in Consumers' service territory. Data center electric demand could require a rapid and significant increase in generation capacity and grid infrastructure in the MISO footprint as well as in Consumers' service territory, which could have a material effect on CMS Energy and Consumers.

Alternatively, this rapid expansion of data centers and resulting increase in demand for electric power in MISO and in Consumers' service territory may not develop as anticipated. Efforts to attract data center developers could be unsuccessful as other utilities and regions compete for these projects, which may limit future load growth. In addition, local zoning, permitting, land-use constraints, and other external factors outside Consumers' control could impede data center development. If these challenges arise and cannot be effectively mitigated, the anticipated benefits of data center load growth may not materialize. Further, even when data center customers enter into contracts to purchase utility service, there is a risk they may not fulfill their contractual or tariff obligations.

CMS Energy and Consumers are subject to information security risks, risks of unauthorized access to their systems, and technology failures.

In the regular course of business, CMS Energy and Consumers handle a range of sensitive confidential security and customer information. In addition, CMS Energy and Consumers operate in a highly regulated industry that requires the continued operation of sophisticated information and control technology systems and network infrastructure. Despite implementation of security measures, technology systems, including disaster recovery and backup systems, are vulnerable to failure, cyber attacks, unauthorized access, and being disabled. These events could impact the reliability of electric generation and electric and gas delivery and also subject CMS Energy and Consumers to financial harm. Cyber attacks, which include the use of malware, ransomware, computer viruses, and other means for disruption or unauthorized access against companies, including CMS Energy and Consumers, are increasing in frequency, scope, and potential impact. While CMS Energy and Consumers have not been subject to cyber incidents that have had a material impact on their operations to date, their security measures in place may be insufficient to prevent a major cyber incident in the future. If technology systems, including disaster recovery and backup systems, were to fail or be breached, CMS Energy and Consumers might not be able to fulfill critical business functions, and sensitive confidential and proprietary data could be compromised. In addition, because CMS Energy's and Consumers' generation, transmission, and distribution systems are part of an interconnected system, a disruption caused by a cyber incident at another utility, electric generator, system operator, or commodity supplier could also adversely affect CMS Energy or Consumers.

A variety of technological tools and systems, including both company-owned IT and technological services provided by outside parties, support critical functions. The failure of these technologies, including backup systems, or the inability of CMS Energy and Consumers to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder their business operations.

CMS Energy’s and Consumers’ businesses have liability risks.

Assets, equipment, and personnel of CMS Energy and Consumers, including electric and gas delivery systems, power plants, gas infrastructure including storage facilities, wind energy or solar equipment, energy products, energy storage assets, vehicle fleets and equipment, other assets, or employees and contractors, could be involved in incidents, failures, or accidents that result in injury, loss of life, or property loss and damage to customers, employees, or the public. Although CMS Energy and Consumers have insurance coverage for many potential incidents (subject to deductibles, limitations, and self-insurance amounts that could be material), depending upon the nature or severity of any incident, failure, or accident, CMS Energy or Consumers could suffer financial loss, reputational damage, and negative repercussions from regulatory agencies or other public authorities, even where there is no legal liability.

CMS Energy and Consumers are subject to risks that are beyond their control, including but not limited to natural disasters, civil unrest, terrorist attacks and related acts of war, cyber incidents, vandalism, and other catastrophic events.

Natural disasters, severe weather, extreme temperatures, wildfires, fires, smoke, flooding, wars, terrorist acts, civil unrest, vandalism, theft, cyber incidents, government shutdowns, pandemics, and other catastrophic events could result in severe damage to CMS Energy’s and Consumers’ assets beyond what could be recovered through insurance policies (which are subject to deductibles, limitations, and self-insurance amounts that could be material), could require CMS Energy and Consumers to incur significant upfront costs, and could severely disrupt operations, resulting in loss of service to customers. There is also a risk that regulators could, after the fact, conclude that Consumers’ preparedness or response to such an event was inadequate and take adverse actions as a result.

Energy risk management strategies might not be effective in managing fuel and electricity pricing risks, which could result in unanticipated liabilities to CMS Energy and Consumers or increased volatility in their earnings.

CMS Energy and Consumers are exposed to changes in market prices for commodities including, but not limited to, natural gas, coal, electric capacity, electric energy, emission allowances, gasoline, diesel fuel, and RECs. CMS Energy and Consumers manage commodity price risk using established policies and procedures, and they may use various contracts to manage this risk, including swaps, options, futures, and forward contracts. No assurance can be made that these strategies will be successful in managing CMS Energy’s and Consumers’ risk or that they will not result in net liabilities to CMS Energy or Consumers as a result of future volatility.

A substantial portion of Consumers’ operating expenses for its electric generating plants and vehicle fleet consists of the costs of obtaining commodities. The contracts associated with Consumers’ fuel for electric generation and purchased power are executed in conjunction with the PSCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its positions in these commodities. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed.

Natural gas prices in particular have been historically volatile. Consumers routinely enters into contracts for natural gas to mitigate exposure to the risks of demand, market effects of weather, and changes in commodity prices associated with the gas distribution business. These contracts are executed in conjunction with the GCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its natural gas positions. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed.

CMS Energy and Consumers do not always hedge any or all of the exposure of their operations from commodity price volatility. Furthermore, the ability to hedge exposure to commodity price volatility depends on liquid commodity markets. As a result, to the extent the commodity markets are illiquid, CMS Energy and Consumers might not be able to execute their risk management strategies, which could result in larger unhedged positions than preferred at a given time. To the extent that unhedged positions exist, fluctuating commodity prices could have a negative effect on CMS Energy and Consumers. Changes in laws that limit CMS Energy's and Consumers' ability to hedge could also have a negative effect on CMS Energy and Consumers.

CMS Energy and Consumers might not be able to obtain an adequate supply of natural gas or coal, which could limit their ability to operate electric generation facilities or serve Consumers' natural gas customers.

CMS Energy and Consumers have contracts in place for the supply and transportation of the natural gas, coal, and other fuel sources they require for their electric generating capacity. Consumers also has interstate transportation and supply agreements in place to facilitate delivery of natural gas to its customers. Apart from the contractual and monetary remedies available to CMS Energy and Consumers in the event of a counterparty's failure to perform under any of these contracts, there can be no assurances that the counterparties to these contracts will fulfill their obligations to provide natural gas or coal to CMS Energy or Consumers. The counterparties under the agreements could experience financial or operational problems that inhibit their ability to fulfill their obligations to CMS Energy or Consumers. In addition, counterparties under these contracts might not be required to supply natural gas or coal to CMS Energy or Consumers under certain circumstances, such as in the event of a natural disaster or severe weather.

If Consumers were unable to obtain its supply requirements, it could be required to purchase natural gas or coal at higher prices, implement its natural gas curtailment program filed with the MPSC, or purchase replacement power at higher prices.

Unplanned outages or maintenance could be costly for CMS Energy or Consumers.

Unforeseen outages or maintenance of the electric and gas delivery systems, power plants, gas infrastructure including storage facilities and compression stations, wind energy or solar equipment, energy storage assets, and energy products owned in whole or in part by CMS Energy or Consumers may be required for many reasons. When unplanned outages occur, CMS Energy and Consumers will not only incur unexpected maintenance expenses, but may also have to make spot market purchases of electric and gas commodities that may exceed CMS Energy's or Consumers' expected cost of generation or gas supply, be forced to curtail services, or retire a given asset if the cost or timing of the maintenance is not reasonable and prudent. Unplanned generator outages could reduce the capacity credit CMS Energy or Consumers receives from MISO and could cause CMS Energy or Consumers to incur additional capacity costs in future years.

General Risk Factors

CMS Energy and Consumers are exposed to counterparty risk.

Adverse economic conditions or financial difficulties experienced by counterparties with whom CMS Energy and Consumers do business could impair the ability of these counterparties to pay for CMS Energy's and Consumers' services and/or fulfill their contractual obligations, including performance and payment of damages. CMS Energy and Consumers depend on these counterparties to remit payments and perform contracted services in a timely and adequate fashion. In addition, any delay or default in payment or performance, including inadequate performance, of contractual obligations (such

as contractual obligations by third parties to purchase utility services, perform work, supply equipment, provide services, and meet related specifications or requirements), could have a material adverse effect on CMS Energy and Consumers.

Volatility and disruptions in capital and credit markets could have a negative impact on CMS Energy's and Consumers' lenders, vendors, contractors, suppliers, customers, and other counterparties, causing them to fail to meet their obligations.

CMS Energy and Consumers are exposed to significant reputational risks.

CMS Energy and Consumers could suffer negative impacts to their reputations as a result of operational incidents, accidents, actual or perceived violations of corporate policies or regulatory violations, inappropriate use of social media, or other events. Reputational damage could have a material adverse effect and could result in negative customer perception and increased regulatory oversight.

A work interruption or other union actions could adversely affect CMS Energy and Consumers.

At December 31, 2025, unions represent 45 percent of Consumers' employees and 22 percent of NorthStar Clean Energy's employees. Consumers' union agreements expire in 2030 and the majority of NorthStar Clean Energy's represented employees have an agreement that expires in 2029. If these employees were to engage in a strike, work stoppage, or other slowdown, CMS Energy or Consumers could experience a significant disruption in its operations and higher ongoing labor costs.

Failure to attract and retain an appropriately qualified workforce could adversely impact CMS Energy's and Consumers' results of operations.

In some areas, competition for skilled employees is high and if CMS Energy and Consumers were unable to match skill sets to future needs, they could encounter operating challenges and increased costs. These challenges could include a lack of resources, loss of knowledge, and delays in skill development. Additionally, higher costs could result from the use of contractors to replace employees, loss of productivity, and safety incidents. Failing to train replacement employees adequately and to transfer internal knowledge and expertise could adversely affect CMS Energy's and Consumers' ability to manage and operate their businesses.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Enterprise Risk Management: CMS Energy and Consumers manage security risks, including cybersecurity risks, through a robust enterprise risk management program that includes people, processes, technology, and governance structures. The enterprise risk management program identifies risks that may significantly impact the business and informs the companies' risk-mitigation strategies. The enterprise risk management program is reviewed with the Board at least annually.

Cybersecurity Program: CMS Energy's and Consumers' security function, led by the Vice President of IT and Security and CIO, is accountable for cyber and physical security and is subject to various state, federal, and industry cybersecurity, physical security, and privacy regulations. Their cybersecurity program is responsible for assessing, identifying, and managing risks from cybersecurity threats using industry frameworks, as well as best practices developed by government and industry partners. All employees and contractors are required to complete annual trainings on a variety of security-related

topics. Additionally, the companies continuously upgrade technological investments designed to prevent, detect, and respond to attacks. The companies' electric, natural gas, and corporate systems each follow standards, controls, and requirements designed to maintain compliance with applicable regulations and standards, such as MPSC, NERC critical infrastructure protection, and payment card industry regulations. Technology projects and third-party service providers are reviewed for adherence to cybersecurity requirements.

CMS Energy's and Consumers' cybersecurity program focuses on finding and remediating vulnerabilities in their systems. The companies use third-party firms for penetration testing, audits, and assessments, and conduct technical exercises to practice their response to simulated events as well as tabletop exercises to test that response using their incident command system, including leadership decisions. The companies also have a dedicated, proactive function focused fully on monitoring CMS Energy's and Consumers' systems and responding when cybersecurity attacks occur. This includes regular information sharing with industry partners, peer utilities, and state and federal partners. The companies' incident response plan outlines the individuals responsible, the methods employed, and the timeline for notifying state and federal governmental agencies. The companies retain a third-party cybersecurity firm to assist with potentially significant cybersecurity incidents and have invested in cybersecurity insurance to offset costs incurred from any such cybersecurity incidents. To manage cybersecurity risks associated with the companies' use of third-party service providers, the companies incorporate security requirements into contracts, when deemed applicable, and pursue third-party security certifications for vendors with a higher risk profile.

CMS Energy and Consumers have experienced no material cybersecurity incidents; however, future cybersecurity incidents could materially affect their business strategy, results of operations, or financial condition. For additional details regarding these and other uncertainties, see Item 1A. Risk Factors.

Management's Role: The Vice President of IT and Security and CIO has over 25 years of IT and security experience and, to enhance governance, reports to the Executive Vice President of Business Transformation and Chief Legal and Administrative Officer. The Vice President of IT and Security and CIO is responsible for informing the CEO and other members of senior management, as necessary, about cybersecurity incidents, covering prevention, detection, mitigation, and remediation efforts as they are detected by the cybersecurity team. Cybersecurity incidents are managed using the companies' standard process for critical events. In the event of such cybersecurity incidents, the Vice President of IT and Security and CIO communicates and collaborates with the officers of the companies and subject matter experts to address business continuity, contingency, and recovery plans. Senior management will notify the Board, including the Audit Committee, of any significant cybersecurity incidents.

Board Oversight: As part of the Board's risk oversight process, senior management meets with the Board or Audit Committee at least twice annually to provide updates on and discuss cybersecurity. Such updates include a review of the companies' cybersecurity strategy, a scan of the threat landscape, and recent performance. Additionally, cybersecurity risks are included in the Audit Committee's risk oversight functions, which focus on operating and financial activities that could impact the companies' financial and other disclosure reporting. The Audit Committee's oversight involves reviewing and approving policies on risk assessment, controls, and accounting risk exposure. The Audit Committee also reviews internal audit reports regarding cybersecurity processes, and receives updates that focus on CMS Energy's and Consumers' cybersecurity program, mitigation of cybersecurity risks, and assessments by third-party experts. Of note, two members of the Board have extensive industry experience in cybersecurity and are on CMS Energy's and Consumers' Audit Committee.

Item 2. Properties

Descriptions of CMS Energy's and Consumers' properties are found in the following sections of Item 1. Business, all of which are incorporated by reference in this Item 2:

- General—CMS Energy
- General—Consumers
- Business Segments—Consumers Electric Utility—Electric Utility Properties
- Business Segments—Consumers Electric Utility—Electric Utility Generation and Supply Mix
- Business Segments—Consumers Gas Utility—Gas Utility Properties
- Business Segments—NorthStar Clean Energy—Non-utility Operations and Investments—Independent Power Production

Item 3. Legal Proceedings

For information regarding CMS Energy's and Consumers' significant pending administrative and judicial proceedings involving regulatory, operating, transactional, environmental, and other matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

CMS Energy, Consumers, and certain of their affiliates are also parties to routine lawsuits and administrative proceedings incidental to their businesses involving, for example, claims for personal injury and property damage, contractual matters, various taxes, and rates and licensing.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

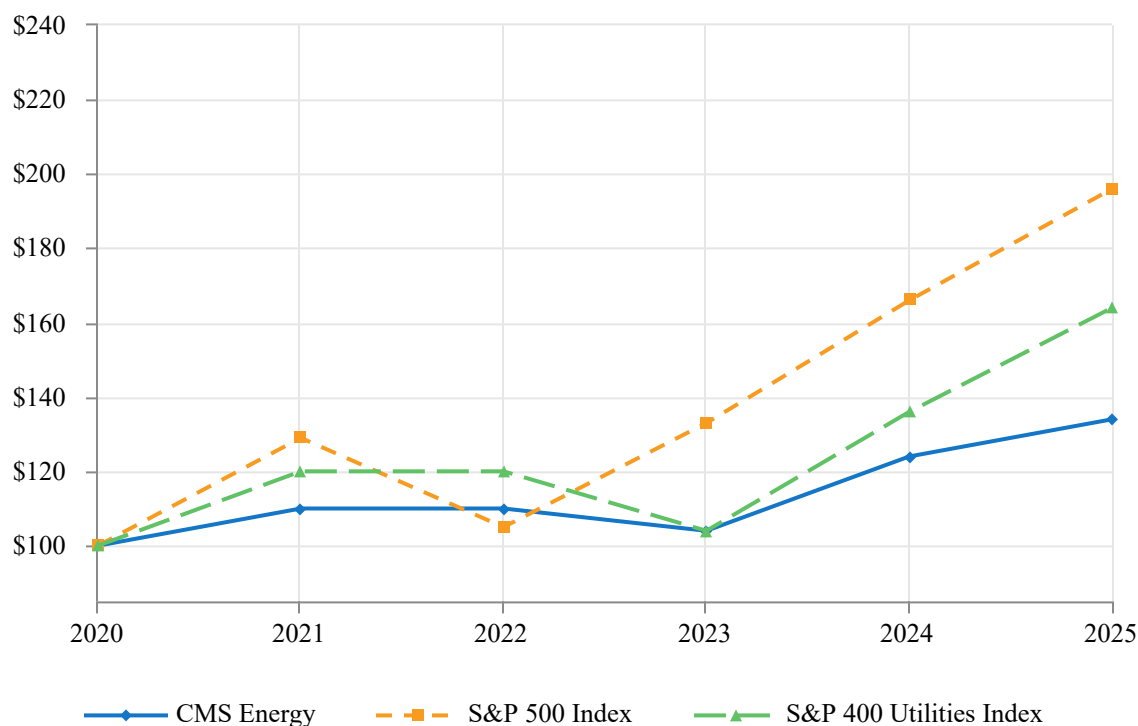
Item 5. Market For Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

CMS Energy

CMS Energy’s common stock is traded on the New York Stock Exchange under the symbol CMS. At January 16, 2026, the number of registered holders of CMS Energy’s common stock totaled 22,938, based on the number of record holders.

For additional information regarding securities authorized for issuance under equity compensation plans, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 12, Stock-based Compensation and Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters. For additional information regarding dividends and dividend restrictions, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Comparison of Five-year Cumulative Total Return



Company/Index	Five-year Cumulative Total Return					
	2020	2021	2022	2023	2024	2025
CMS Energy	\$ 100	\$ 110	\$ 110	\$ 104	\$ 124	\$ 134
S&P 500 Index	100	129	105	133	166	196
S&P 400 Utilities Index	100	120	120	104	136	164

These cumulative total returns assume reinvestments of dividends.

Consumers

Consumers' common stock is privately held by its parent, CMS Energy, and does not trade in the public market.

Issuer Repurchases of Equity Securities

CMS Energy repurchases common stock to satisfy the minimum statutory income tax withholding obligation for common shares that have vested under the PISP. The value of shares repurchased is based on the market price on the vesting date. Presented in the following table are CMS Energy's repurchases of common stock for the three months ended December 31, 2025:

Period	Total Number	
	of Shares Purchased	Average Price Paid Per Share
October 1, 2025 to October 31, 2025	—	\$ —
November 1, 2025 to November 30, 2025	132	73.99
December 1, 2025 to December 31, 2025	320	69.84
Total	452	\$ 71.05

As of December 31, 2025, CMS Energy has no other publicly announced plans or programs that permit the repurchase of equity securities.

Unregistered Sales of Equity Securities

None.

Item 6. Reserved

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

This Management’s Discussion and Analysis of Financial Condition and Results of Operations is a combined report of CMS Energy and Consumers.

Executive Overview

CMS Energy is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy, primarily a domestic independent power producer and marketer. Consumers’ electric utility operations include the generation, purchase, distribution, and sale of electricity, and Consumers’ gas utility operations include the purchase, transmission, storage, distribution, and sale of natural gas. Consumers’ customer base consists of a mix of primarily residential, commercial, and diversified industrial customers. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production.

CMS Energy and Consumers manage their businesses by the nature of services each provides. CMS Energy operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers operates principally in two business segments: electric utility and gas utility. CMS Energy’s and Consumers’ businesses are affected primarily by:

- regulation and regulatory matters
- state and federal legislation
- economic conditions
- load growth
- weather
- energy commodity prices
- interest rates
- their securities’ credit ratings

The Triple Bottom Line

CMS Energy’s and Consumers’ purpose is to provide safe, reliable, affordable, clean, and equitable energy in service of their customers. In support of this purpose, CMS Energy and Consumers couple digital transformation with the “CE Way,” a lean operating system designed to improve safety, quality, cost, delivery, and employee morale.

CMS Energy and Consumers measure their progress toward the purpose by considering their impact on the “triple bottom line” of people, planet, and prosperity; this consideration takes into account not only the economic value that CMS Energy and Consumers create for customers and investors, but also their responsibility to social and environmental goals. The triple bottom line balances the interests of employees, customers, suppliers, regulators, creditors, Michigan’s residents, the investment community, and other stakeholders, and it reflects the broader societal impacts of CMS Energy’s and Consumers’ activities.



CMS Energy’s Sustainability Report, which is available to the public, describes CMS Energy’s and Consumers’ progress toward world class performance measured in the areas of people, planet, and prosperity.

People: The people element of the triple bottom line represents CMS Energy’s and Consumers’ commitment to their employees, their customers, the residents of local communities in which they do business, and other stakeholders.

The safety of co-workers, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions.

CMS Energy and Consumers also place a high priority on customer value and on providing reliable, affordable, and equitable energy in service of their customers. Consumers’ customer-driven investment program is aimed at improving safety and increasing electric and gas reliability.

In the electric rate case it filed with the MPSC in June 2025, Consumers updated its Reliability Roadmap, a five-year strategy to improve Consumers’ electric distribution system and the reliability of the grid. The plan proposes spending through 2029 for projects designed to reduce the number and duration of power outages to customers through investment in infrastructure upgrades, vegetation management, and grid

modernization. Consumers has requested rate recovery of the investments needed to achieve the Reliability Roadmap's key objectives in its electric rate cases.

Central to Consumers' commitment to its customers are the initiatives it has undertaken to keep electricity and natural gas affordable, including:

- replacement of coal-fueled generation and PPAs with a cost-efficient and reliable mix of renewable energy, less-costly dispatchable generation sources, and energy waste reduction and demand response programs
- targeted infrastructure investment to reduce maintenance costs and improve reliability and safety
- supply chain optimization
- economic development to increase sales and reduce overall rates
- information and control system efficiencies
- employee and retiree health care cost sharing
- tax planning
- cost-effective financing
- workforce productivity enhancements

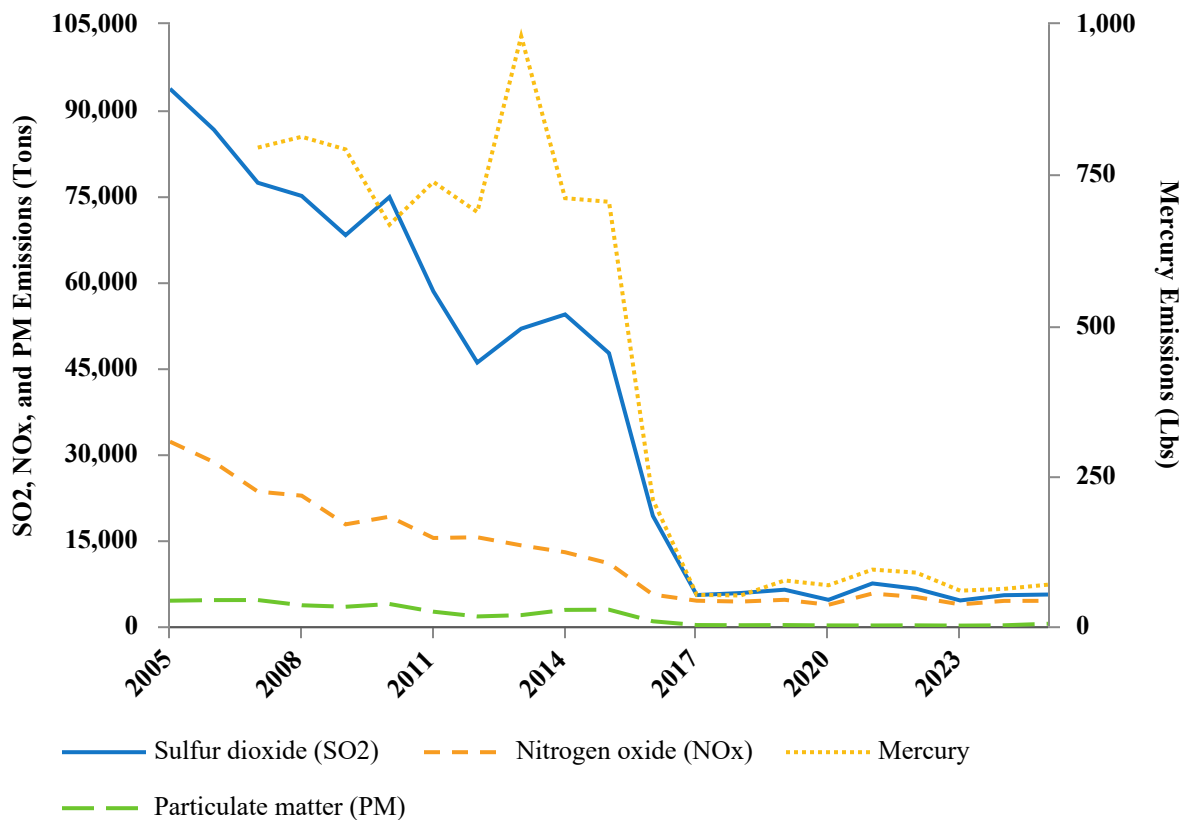
While inflationary pressures and tariffs could impact supply chain availability and pricing, CMS Energy and Consumers are taking steps to help mitigate the impact on their ability to provide safe, reliable, affordable, clean, and equitable energy in service of their customers.

Planet: The planet element of the triple bottom line represents CMS Energy's and Consumers' commitment to protect the environment. This commitment extends beyond compliance with various state and federal environmental, health, and safety laws and regulations. Management considers climate change and other environmental risks in strategy development, business planning, and enterprise risk management processes.

CMS Energy and Consumers continue to focus on opportunities to protect the environment and reduce their carbon footprint from owned generation. CMS Energy, including Consumers, has decreased its combined percentage of electric supply (self-generated and purchased) from coal by 24 percentage points since 2015. Additionally, as a result of actions already taken through 2025, preliminary data indicates Consumers has:

- reduced carbon dioxide emissions from owned generation by nearly 30 percent since 2005
- reduced methane emissions by more than 40 percent since 2012
- reduced the volume of water used to generate electricity by nearly 60 percent since 2012
- reduced landfill waste disposal by more than 2 million tons since 1992
- enhanced, restored, or protected more than 13,500 acres of land since 2017
- reduced sulfur dioxide and particulate matter emissions by more than 90 percent since 2005
- reduced NOx emissions by more than 85 percent since 2005
- reduced mercury emissions by more than 90 percent since 2007

Presented in the following illustration are Consumers’ reductions in these emissions:



In 2023, Michigan enacted the 2023 Energy Law, which among other things:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035; renewable energy generated anywhere within MISO can be applied to meeting this standard, with certain limitations
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- enhanced existing incentives for energy efficiency programs and returns earned on new clean or renewable PPAs
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW
- expanded the statutory cap on distributed generation resources to 10 percent of the electric utility’s five-year average peak load

Consumers’ Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers’ Renewable Energy Plan. The Electric Supply Plan is Consumers’ blueprint for compliance with Michigan’s 2023 Energy Law and for advancing sustainability objectives.

To meet these objectives, Consumers is executing a multi-faceted strategy. This strategy involves taking steps to end the use of coal, including the retirement of the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, in 2023 and obtaining MPSC approval to retire J.H. Campbell, totaling 1,407 MW of nameplate capacity. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For a more detailed

discussion of the emergency orders, see Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

To continue providing controllable sources of electricity to customers, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023 and has solicited additional capacity from controllable sources of electricity to customers.

Consumers' updates to its Renewable Energy Plan include up to 9,000 MW of both purchased and owned solar energy resources and up to 4,000 MW of wind energy resources. Coupled with updates to its integrated resource plan, these actions position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040, and will also contribute to Consumers' achievement of the emissions reductions goals discussed below.

Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. To date, Consumers has reduced methane emissions by more than 40 percent.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers expects to meet this goal through carbon offset measures, renewable natural gas, energy efficiency and demand response programs, and the adoption of cost-effective emerging technologies once proven and commercially available.

Additionally, to advance its environmental stewardship in Michigan and to minimize the impact of future regulations, Consumers set the following goals for the five-year period 2023 through 2027:

- to enhance, restore, or protect 6,500 acres of land through 2027; Consumers surpassed this goal during the three-year period 2023 through 2025 and enhanced, restored, or protected 6,700 acres of land
- to reduce water usage by 1.7 billion gallons through 2027; Consumers had reduced water usage by more than 1.9 billion gallons towards this goal
- to annually divert a minimum of 90 percent of waste from landfills (through waste reduction, recycling, and reuse); during 2025, Consumers' rate of waste diverted from landfills was 93 percent

CMS Energy and Consumers are monitoring numerous legislative, policy, executive, and regulatory initiatives, including those related to regulation and reporting of greenhouse gases, and related litigation. While CMS Energy and Consumers cannot predict the outcome of these matters, which could affect them materially, they intend to continue to move forward with a triple-bottom-line approach that focuses on people, planet, and prosperity.

Prosperity: The prosperity element of the triple bottom line represents CMS Energy's and Consumers' commitment to meeting their financial objectives and providing economic development opportunities and benefits in the communities in which they do business. CMS Energy's and Consumers' financial strength allows them to maintain solid investment-grade credit ratings and thereby reduce funding costs for the benefit of customers and investors, to attract and retain talent, and to reinvest in the communities they serve.

In 2025, CMS Energy's net income available to common stockholders was \$1.1 billion, and diluted EPS were \$3.53. This compares with net income available to common stockholders of \$993 million and diluted EPS of \$3.33 in 2024. In 2025, higher gas and electric sales, due primarily to favorable weather, and electric and gas rate increases were offset partially by increased depreciation and property taxes, reflecting higher capital spending, and higher interest charges. A more detailed discussion of the factors affecting CMS Energy's and Consumers' performance can be found in the Results of Operations section that follows this Executive Overview.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2025. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Weather-normalized gas deliveries are expected to remain stable relative to 2025, reflecting modest growth in gas demand, offset by the effects of energy waste reduction programs.

Performance: Impacting the Triple Bottom Line

CMS Energy and Consumers remain committed to delivering safe, reliable, affordable, clean, and equitable energy in service of their customers and positively impacting the triple bottom line of people, planet, and prosperity. During 2025, CMS Energy and Consumers:

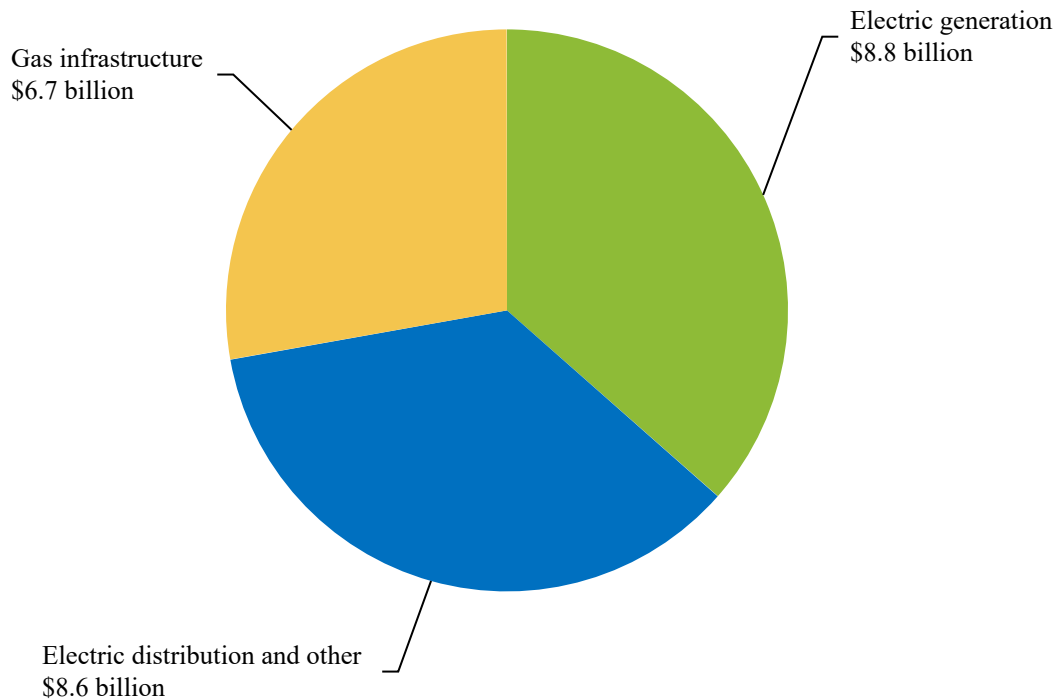
- connected over 140,000 customers with \$60 million in energy-bill assistance and helped make over \$100 million in statewide aid available for 2026, reinforcing Consumers' commitment to affordability
- began operations at Muskegon Solar Energy Center, a 1,900-acre project generating 250 MW of clean energy to power 40,000 homes and businesses, supporting Michigan's energy needs and advancing the company's long-term clean energy strategy
- reached an agreement with a new data center expected to add more than 1 GW of incremental load growth in our service territory, supporting long-term sales growth and delivering economic benefits for Michigan
- expanded the use of drone technology enabling faster, safer inspections of 400 miles of hard-to-reach power lines and infrastructure resulting in reduced average outage time per customer and improved storm recovery capabilities
- announced the launch of "Green Giving," a program enabling the general public to contribute to renewable energy while offering financial benefits to low-income customers, along with a new Residential Renewable Energy Program, which allows customers of all income levels to subscribe and match their energy usage with renewable energy sources, supporting clean energy initiatives
- moved forward with an aggressive plan to enhance grid reliability for nearly 2 million homes and businesses by clearing trees along 8,000 miles of power lines and creating a modern, stronger, and more resilient power grid through infrastructure upgrades and technology investments
- deployed eight state-of-the-art vehicles that survey the company's nearly 30,000-mile gas distribution system to find methane emissions, enhancing safety and reliability for Consumers' natural gas customers
- experienced success with the underground power line pilot program in early 2025, with pilot areas seeing 100-percent reduction in storm-related outages and improved customer satisfaction

CMS Energy and Consumers will continue to utilize the CE Way to enable them to achieve world class performance and positively impact the triple bottom line. Consumers' investment plan and the regulatory environment in which it operates also drive its ability to impact the triple bottom line.

Investment Plan: Over the next five years, Consumers expects to make significant expenditures on infrastructure upgrades, replacements, and clean generation. While it has a large number of potential investment opportunities that would add customer value, Consumers has prioritized its spending based on

the criteria of enhancing public safety, increasing reliability, maintaining affordability for its customers, and advancing its environmental stewardship. Consumers' investment program, which is subject to approval through general rate case and other MPSC proceedings, is expected to result in annual rate-base growth of more than 8 percent. This rate-base growth, together with cost-control measures, should allow Consumers to maintain affordable customer prices.

Presented in the following illustration are Consumers' planned capital expenditures through 2030 of \$24.1 billion:



Of this amount, Consumers plans to spend \$8.8 billion on electric generation, which includes solar, wind, and natural gas-fueled generation, as well as energy storage. Consumers also expects to spend \$15.3 billion over the next five years primarily to maintain and upgrade its electric distribution systems and gas infrastructure in order to enhance safety and reliability, improve customer satisfaction, reduce energy waste on those systems, and facilitate its clean energy transformation. Electric distribution and other projects comprise \$8.6 billion primarily to strengthen circuits and substations, replace poles, and interconnect clean energy resources. The gas infrastructure projects comprise \$6.7 billion to sustain deliverability, enhance pipeline integrity and safety, and reduce methane emissions.

Regulation: Regulatory matters are a key aspect of Consumers' business, particularly rate cases and regulatory proceedings before the MPSC, which permit recovery of new investments while helping to ensure that customer rates are fair and affordable. Important regulatory events and developments not already discussed are summarized below.

2024 Electric Rate Case: In March 2025, the MPSC issued an order authorizing an annual rate increase of \$176 million, which is inclusive of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of \$460 million, made up of two components. First, Consumers requested a \$436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a \$24 million surcharge for the recovery of distribution investments made during the 12 months ended February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders. In October 2025, Consumers revised its requested increase to \$447 million, which includes the \$24 million surcharge to recover deferred distribution investments. The MPSC must issue a final order in this case before or in April 2026.

2024 Gas Rate Case: In September 2025, the MPSC issued an order authorizing an annual rate increase of \$157.5 million, based on a 9.80-percent authorized return on equity. The new rates became effective in November 2025.

2025 Gas Rate Case: In December 2025, Consumers filed an application with the MPSC seeking an annual rate increase of \$240 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2027. The MPSC must issue a final order in this case before or in October 2026.

Looking Forward

CMS Energy and Consumers will continue to consider the impact on the triple bottom line of people, planet, and prosperity in their daily operations as well as in their long-term strategic decisions. Consumers will continue to seek fair and timely regulatory treatment that will support its customer-driven investment plan, while pursuing cost-control measures that will allow it to maintain sustainable customer base rates. The CE Way is an important means of realizing CMS Energy's and Consumers' purpose of providing safe, reliable, affordable, clean, and equitable energy in service of their customers.

Results of Operations

CMS Energy Consolidated Results of Operations

	<i>In Millions, Except Per Share Amounts</i>		
Years Ended December 31	2025	2024	Change
Net Income Available to Common Stockholders	\$ 1,061	\$ 993	\$ 68
Basic Earnings Per Average Common Share	\$ 3.53	\$ 3.34	\$ 0.19
Diluted Earnings Per Average Common Share	\$ 3.53	\$ 3.33	\$ 0.20

	<i>In Millions</i>		
Years Ended December 31	2025	2024	Change
Electric utility	\$ 719	\$ 681	\$ 38
Gas utility	409	328	81
NorthStar Clean Energy	71	63	8
Corporate interest and other	(138)	(79)	(59)
Net Income Available to Common Stockholders	\$ 1,061	\$ 993	\$ 68

For a summary of net income available to common stockholders for 2024 versus 2023, as well as detailed changes by reportable segment, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations, in the [Form 10-K for the fiscal year ended December 31, 2024, filed February 11, 2025](#).

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Presented in the following table is a summary of changes to net income available to common stockholders for 2025 versus 2024:

	<i>In Millions</i>
Year Ended December 31, 2024	\$ 993
<i>Reasons for the change</i>	
<i>Consumers electric utility and gas utility</i>	
Electric sales	\$ 49
Gas sales	151
Electric rate increase	210
Gas rate increase, including gain amortization in lieu of rate relief	71
Lower coal-fueled generation costs ¹	26
Higher income tax expenses	(87)
Higher depreciation and amortization	(63)
Higher interest charges	(43)
Higher property taxes, reflecting higher capital spending	(29)
Higher IT expenses, including early-phase ERP implementation costs	(27)
Higher service restoration costs, net of 2025 deferred storm expense ²	(25)
Higher vegetation management costs	(25)
Higher other electric distribution costs	(13)
Higher other electric supply costs	(21)
Higher other maintenance and operating expenses	(30)
Impairment of project development assets	(15)
Absence of ASP revenue, net of expense, due to sale in 2024 ³	(5)
Lower other income, net of expenses	(5)
	\$ 119
NorthStar Clean Energy	8
Corporate interest and other	(59)
Year Ended December 31, 2025	\$ 1,061

¹ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Consumers Electric Utility—J.H. Campbell Emergency Order.

² See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Assets—Service Restoration Cost Deferral.

³ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Liabilities—ASP Gain.

Consumers Electric Utility Results of Operations

Presented in the following table are the detailed changes to the electric utility's net income available to common stockholders for 2025 versus 2024:

	<i>In Millions</i>
Year Ended December 31, 2024	\$ 681
<i>Reasons for the change</i>	
<i>Electric deliveries¹ and rate increases</i>	
Rate increase, including return on higher renewable capital spending	\$ 210
Higher revenue due primarily to higher sales volume	29
Lower energy waste reduction program revenues	(8)
Higher other revenues	20
	\$ 251
<i>Maintenance and other operating expenses</i>	
Lower coal-fueled generation costs ²	26
Lower energy waste reduction program costs	8
Higher service restoration costs, net of 2025 deferred storm expense ³	(25)
Higher vegetation management costs	(25)
Higher other supply costs	(21)
Higher IT expenses, including early-phase ERP implementation costs	(19)
Higher other distribution costs	(13)
Higher other maintenance and operating expenses	(11)
	(80)
<i>Depreciation and amortization</i>	
Increased plant in service, reflecting higher capital spending	(38)
<i>General taxes</i>	
Higher property taxes, reflecting higher capital spending	(16)
<i>Other income, net of expenses</i>	
	(2)
<i>Interest charges</i>	
	(29)
<i>Income taxes</i>	
Higher electric utility pre-tax earnings	(25)
Absence of 2024 deferred tax liability reversals	(11)
State deferred tax remeasurement ⁴	(8)
Higher other income taxes	(4)
	(48)
Year Ended December 31, 2025	\$ 719

¹ Deliveries to end-use customers were 37.4 billion kWh in 2025 and 36.8 billion kWh in 2024.

² See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Consumers Electric Utility—J.H. Campbell Emergency Order.

³ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Assets—Service Restoration Cost Deferral.

⁴ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

Consumers Gas Utility Results of Operations

Presented in the following table are the detailed changes to the gas utility's net income available to common stockholders for 2025 versus 2024:

	<i>In Millions</i>
Year Ended December 31, 2024	\$ 328
<i>Reasons for the change</i>	
<i>Gas deliveries¹ and rate increases</i>	
Rate increase	\$ 60
Higher revenue due primarily to the absence of 2024 unfavorable weather	155
Higher energy waste reduction program revenues	16
Absence of ASP business revenue ²	(19)
ASP gain customer bill credit ²	(20)
Lower other revenues	(3)
	<u>\$ 189</u>
<i>Maintenance and other operating expenses</i>	
Amortization of ASP gain ²	30
Absence of 2024 ASP business expense ²	14
Higher energy waste reduction program costs	(16)
Impairment of project development assets	(15)
Higher IT expenses, including early-phase ERP implementation costs	(8)
Higher maintenance and other operating expenses	(19)
	<u>(14)</u>
<i>Depreciation and amortization</i>	
Increased plant in service, reflecting higher capital spending	(25)
<i>General taxes</i>	
Higher property taxes, reflecting higher capital spending	(13)
<i>Other income, net of expenses</i>	
	(3)
<i>Interest charges</i>	
	(14)
<i>Income taxes</i>	
Higher gas utility pre-tax earnings	(31)
Absence of 2024 deferred tax liability reversals	(5)
State deferred tax remeasurement ³	(4)
Lower other income taxes	1
	<u>(39)</u>
Year Ended December 31, 2025	\$ 409

¹ Deliveries to end-use customers were 311 Bcf in 2025 and 268 Bcf in 2024.

² See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Liabilities—ASP Gain.

³ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

NorthStar Clean Energy Results of Operations

Presented in the following table are the detailed changes to NorthStar Clean Energy’s net income available to common stockholders for 2025 versus 2024:

	<i>In Millions</i>
Year Ended December 31, 2024	\$ 63
<i>Reason for the change</i>	
Higher renewable earnings primarily driven by new project development	\$ 26
Lower other expenses	7
Higher tax expenses	(3)
Lower operating earnings, due primarily to planned major outage at DIG	(22)
Year Ended December 31, 2025	\$ 71

Corporate Interest and Other Results of Operations

Presented in the following table are the detailed changes to corporate interest and other results for 2025 versus 2024:

	<i>In Millions</i>
Year Ended December 31, 2024	\$ (79)
<i>Reasons for the change</i>	
Higher interest charges	\$ (61)
Lower gains on extinguishment of debt ¹	(38)
Higher interest earnings and other	21
Lower tax expense	19
Year Ended December 31, 2025	\$ (138)

¹ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization—CMS Energy’s Purchase of Consumers’ First Mortgage Bonds.

Cash Position, Investing, and Financing

At December 31, 2025, CMS Energy had \$615 million of consolidated cash and cash equivalents, which included \$106 million of restricted cash and cash equivalents. At December 31, 2025, Consumers had \$111 million of consolidated cash and cash equivalents, which included \$86 million of restricted cash and cash equivalents.

For specific components of net cash provided by operating activities, net cash used in investing activities, and net cash provided by financing activities for 2024 versus 2023, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Cash Position, Investing, and Financing, in the [Form 10-K for the fiscal year ended December 31, 2024, filed February 11, 2025](#).

Operating Activities

Presented in the following table are specific components of net cash provided by operating activities for 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Year Ended December 31, 2024	\$ 2,370
<i>Reasons for the change</i>	
Higher net income	\$ 55
Non-cash transactions ¹	133
Unfavorable impact of changes in core working capital, ² due primarily to fluctuations in gas prices and higher undercollections of PSCR	(107)
Unfavorable impact of changes in other assets and liabilities, due primarily to lower tax-credit sale proceeds and higher service restoration ³ and renewable energy expenditures	(216)
Year Ended December 31, 2025	\$ 2,235
Consumers	
Year Ended December 31, 2024	\$ 2,446
<i>Reasons for the change</i>	
Higher net income	\$ 120
Non-cash transactions ¹	(26)
Unfavorable impact of changes in core working capital, ² due primarily to fluctuations in gas prices and higher undercollections of PSCR	(102)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher income tax payments to CMS Energy and service restoration ³ and renewable energy expenditures	(200)
Year Ended December 31, 2025	\$ 2,238

¹ Non-cash transactions comprise depreciation and amortization, changes in deferred income taxes and investment tax credits, bad debt expense, and other non-cash operating activities and reconciling adjustments.

² Core working capital comprises accounts receivable, accrued revenue, inventories, accounts payable, and accrued rate refunds.

³ See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Investing Activities

Presented in the following table are specific components of net cash used in investing activities for 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Year Ended December 31, 2024	\$ (3,054)
<i>Reasons for the change</i>	
Higher capital expenditures	\$ (806)
Absence of proceeds from sale of ASP business in 2024	(124)
Other investing activities, primarily higher cost to retire property	(54)
Year Ended December 31, 2025	\$ (4,038)
Consumers	
Year Ended December 31, 2024	\$ (2,872)
<i>Reasons for the change</i>	
Higher capital expenditures	\$ (472)
Absence of proceeds from sale of ASP business in 2024	(124)
Other investing activities, primarily higher cost to retire property	(67)
Year Ended December 31, 2025	\$ (3,535)

Financing Activities

Presented in the following table are specific components of net cash provided by financing activities for 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Year Ended December 31, 2024	\$ 614
<i>Reasons for the change</i>	
Higher debt issuances	\$ 1,647
Higher debt retirements	(198)
Higher repayments of notes payable	(37)
Higher issuances of common stock	239
Higher payments of dividends on common stock	(37)
Proceeds from sale of membership interests in VIEs	59
Lower contributions from noncontrolling interest	(1)
Higher distributions to noncontrolling interest	(2)
Other financing activities, primarily higher debt issuance costs	(44)
Year Ended December 31, 2025	\$ 2,240
Consumers	
Year Ended December 31, 2024	\$ 489
<i>Reasons for the change</i>	
Lower debt issuances	\$ (174)
Lower debt retirements	274
Higher repayments of notes payable	(37)
Borrowings from CMS Energy	340
Higher stockholder contribution from CMS Energy	185
Absence of return of stockholder contribution to CMS Energy in 2024	320
Higher payments of dividends on common stock	(103)
Other financing activities	(5)
Year Ended December 31, 2025	\$ 1,289

Capital Resources and Liquidity

CMS Energy and Consumers expect to have sufficient liquidity to fund their present and future commitments. CMS Energy uses dividends and tax-sharing payments from its subsidiaries and external financing and capital transactions to invest in its utility and non-utility businesses, retire debt, pay dividends, and fund its other obligations. The ability of CMS Energy's subsidiaries, including Consumers, to pay dividends to CMS Energy depends upon each subsidiary's revenues, earnings, cash needs, and other factors. In addition, Consumers' ability to pay dividends is restricted by certain terms included in its articles of incorporation and potentially by FERC requirements and provisions under the Federal Power Act and the Natural Gas Act. For additional details on Consumers' dividend restrictions, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization—Dividend Restrictions. During the year ended December 31, 2025, Consumers paid \$898 million in dividends on its common stock to CMS Energy.

Consumers uses cash flows generated from operations, external financing transactions, and the monetization of tax credits, along with stockholder contributions from CMS Energy, to fund capital expenditures, retire debt, pay dividends, and fund its other obligations. Consumers also uses these sources of funding to contribute to its employee benefit plans.

Financing and Capital Resources: CMS Energy and Consumers rely on the capital markets to fund their robust capital plan. Barring any sustained market dislocations or disruptions, CMS Energy and Consumers expect to continue to have ready access to the financial and capital markets and will continue to explore possibilities to take advantage of market opportunities as they arise with respect to future funding needs. If access to these markets were to diminish or otherwise become restricted, CMS Energy and Consumers would implement contingency plans to address debt maturities, which could include reduced capital spending.

In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to \$1 billion in privately negotiated transactions, in “at the market” offerings, or through forward sales transactions. During the year ended December 31, 2025, CMS Energy settled forward sale contracts issued under this program, resulting in net proceeds of \$497 million. Following these settlements, CMS Energy has \$8 million in outstanding forward contracts under the program, maturing November 30, 2026.

CMS Energy, NorthStar Clean Energy, and Consumers use revolving credit facilities for general working capital purposes and to issue letters of credit. At December 31, 2025, CMS Energy had \$715 million of its revolving credit facility available, NorthStar Clean Energy had \$5 million available under its revolving credit facility, and Consumers had \$1.4 billion available under its revolving credit facilities.

An additional source of liquidity is Consumers' commercial paper program, which allows Consumers to issue, in one or more placements, up to \$500 million in aggregate principal amount of commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers' revolving credit facilities. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At December 31, 2025, there were no commercial paper notes outstanding under this program.

For additional details about these programs and facilities, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Certain of CMS Energy’s, NorthStar Clean Energy’s, and Consumers’ credit agreements contain covenants that require each entity to maintain certain financial ratios, as defined therein. At December 31, 2025, no default had occurred with respect to any of the financial covenants contained in these credit agreements. Each of the entities was in compliance with the covenants contained in their respective credit agreements as of December 31, 2025, as presented in the following table:

	Limit	Actual
CMS Energy, parent only		
Debt to capital ¹	≤ 0.70 to 1.0	0.56 to 1.0
NorthStar Clean Energy		
Debt to capital ²	≤ 0.50 to 1.0	0.14 to 1.0
Debt service coverage ²	≥ 2.00 to 1.0	5.03 to 1.0
Pledged equity interests to aggregate commitment ^{2,3}	≥ 2.00 to 1.0	2.06 to 1.0
Consumers		
Debt to capital ⁴	< 0.65 to 1.0	0.51 to 1.0

¹ Applies to CMS Energy’s revolving credit agreement and letter of credit reimbursement agreement.

² Applies to NorthStar Clean Energy’s revolving credit agreement.

³ The aggregate book value of the pledged equity interests under the revolving credit agreement was at least two-times the aggregate commitment under the revolving credit agreement at December 31, 2025.

⁴ Applies to Consumers’ revolving credit agreements and certain letter of credit reimbursement agreements.

Material Cash Requirements: Based on the present investment plan, during 2026, CMS Energy, including Consumers, projects capital expenditures of \$4.4 billion and Consumers projects capital expenditures of \$4.1 billion. CMS Energy’s 2026 contractual commitments comprise \$2.4 billion of purchase obligations and \$1.8 billion of principal and interest payments on long-term debt. Consumers’ 2026 contractual commitments comprise \$2.1 billion of purchase obligations and \$1.1 billion of principal and interest payments on long-term debt.

Components of CMS Energy’s and Consumers’ cash management plan include controlling operating expenses and capital expenditures and evaluating market conditions for financing and refinancing opportunities. CMS Energy’s and Consumers’ present level of cash and expected cash flows from operating activities, together with access to sources of liquidity, are anticipated to be sufficient to fund contractual obligations and other material cash requirements for 2026 and beyond.

Capital Expenditures: Over the next five years, CMS Energy and Consumers expect to make substantial capital investments. The companies may revise their forecast of capital expenditures periodically due to a number of factors, including environmental regulations, MPSC approval or disapproval, business opportunities, market volatility, economic trends, and the ability to access capital. Presented in the

following table are CMS Energy's and Consumers' estimated capital expenditures, including lease commitments, for 2026 through 2030:

	<i>In Billions</i>					
	2026	2027	2028	2029	2030	Total
CMS Energy, including Consumers						
Consumers	\$ 4.1	\$ 5.4	\$ 5.7	\$ 5.0	\$ 3.9	\$ 24.1
NorthStar Clean Energy	0.3	0.4	0.5	0.4	0.1	1.7
Total CMS Energy	\$ 4.4	\$ 5.8	\$ 6.2	\$ 5.4	\$ 4.0	\$ 25.8
Consumers						
Electric utility operations	\$ 3.0	\$ 4.1	\$ 4.4	\$ 3.5	\$ 2.4	\$ 17.4
Gas utility operations	1.1	1.3	1.3	1.5	1.5	6.7
Total Consumers	\$ 4.1	\$ 5.4	\$ 5.7	\$ 5.0	\$ 3.9	\$ 24.1

Other Material Cash Requirements: Presented in the following table are CMS Energy's and Consumers' material cash obligations from known contractual and other legal obligations:

	<i>In Billions</i>	
December 31, 2025	Payments Due	
	Less Than One Year	Total
CMS Energy, including Consumers		
Long-term debt	\$ 1.0	\$ 18.9
Interest payments on long-term debt	0.8	15.1
Purchase obligations	2.4	20.6
AROs	0.1	2.7
Total obligations	\$ 4.3	\$ 57.3
Consumers		
Long-term debt	\$ 0.6	\$ 13.2
Interest payments on long-term debt	0.5	8.0
Purchase obligations	2.1	19.7
AROs	0.1	2.6
Total obligations	\$ 3.3	\$ 43.5

Purchase obligations arise from long-term contracts for the purchase of commodities and related services, primarily long-term PPAs, and construction and service agreements. For more information on CMS Energy's and Consumers' purchase obligations, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.

CMS Energy, Consumers, and certain of their subsidiaries enter into various arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include indemnities, surety bonds, letters of credit, and financial and performance guarantees. For additional details on indemnity and guarantee arrangements, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Guarantees. For additional details on letters of credit and CMS Energy's forward sales contracts, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Outlook

Several business trends and uncertainties may affect CMS Energy's and Consumers' financial condition and results of operations. These trends and uncertainties could have a material impact on CMS Energy's and Consumers' consolidated income, cash flows, or financial position.

During 2025, the federal government took numerous executive actions related to tariffs and trade, alleviating regulatory burdens, and environmental regulations and enforcement, among other areas of potential impact. Many of these actions require further implementation by federal agencies and departments, and some of these actions will likely be subject to further judicial review. CMS Energy and Consumers continue to monitor these executive actions and will continue taking steps to deliver consistently on the triple bottom line.

For additional details regarding these and other uncertainties, see Forward-looking Statements and Information; Item 1A. Risk Factors; and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Consumers Electric Utility Outlook and Uncertainties

Energy Supply: Consumers' Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers' Renewable Energy Plan. The Electric Supply Plan is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives.

Among other things, the 2023 Energy Law:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW; the MPSC Staff has indicated that Consumers' share of this target is 817 MW

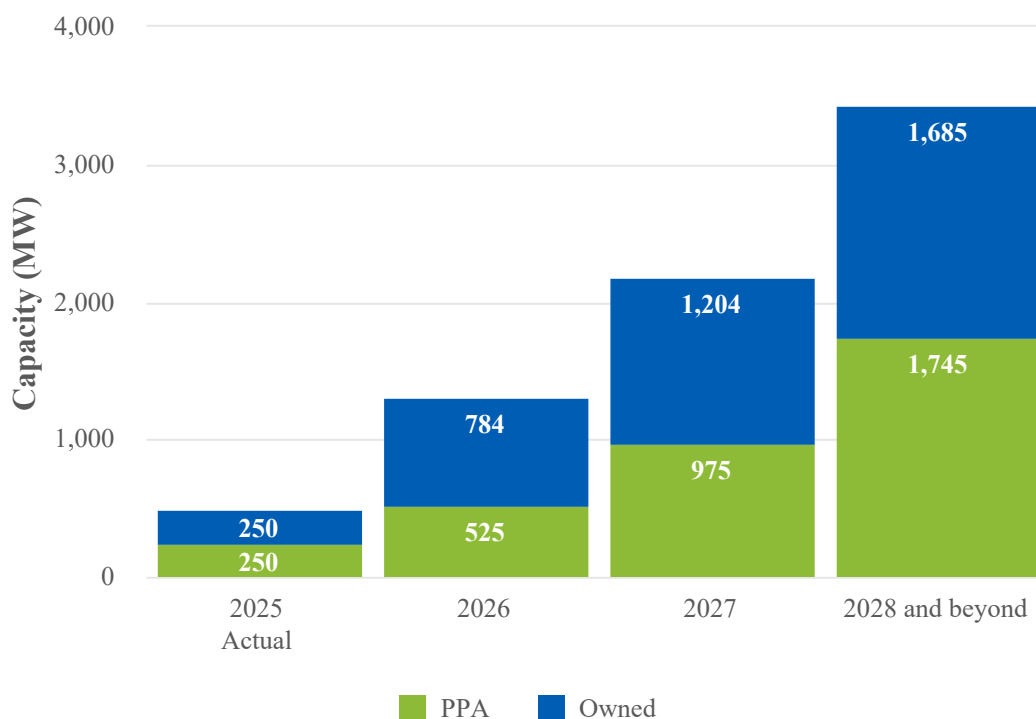
Consumers' integrated resource planning process provides a clear path toward these goals. Updates to its integrated resource plan will be filed in 2026 to reinforce and expand that pathway, while recent updates to the Renewable Energy Plan—approved by the MPSC in September 2025—position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040.

To meet these objectives, Consumers is executing a multi-faceted strategy:

- Ending the use of coal—In 2023, Consumers retired the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, and as authorized by the MPSC, issued securitization bonds to finance the recovery of and return on those units. Additionally, Consumers obtained MPSC approval to retire J.H. Campbell in May 2025, totaling 1,407 MW of nameplate capacity, and to recover its remaining book value plus a 9.0-percent return on equity through regulatory asset treatment upon its retirement. As discussed further below, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy.

- Resource adequacy and reliability—To maintain reliability during the transition, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023. Additionally, in September 2025, Consumers entered into a new 10-year PPA with the MCV Partnership for the purchase of up to 1,240 MW of capacity and associated energy from the MCV Facility, effective June 1, 2030.
- Energy storage investments—Consumers has contracted to purchase 850 MW of capacity from battery storage facilities to be located in Michigan’s Lower Peninsula and with expected commercial operation dates through 2028.
- Renewable expansion—Recent Renewable Energy Plan updates include up to 4,000 MW of wind energy resources and up to 9,000 MW of both purchased and owned solar energy resources, of which 1,060 MW will support Consumers’ voluntary green pricing program.

Presented in the following illustration is the aggregate renewable capacity that Consumers expects to add to its portfolio through PPAs and owned generation under its integrated resource plan, voluntary green pricing program, and Renewable Energy Plan updates:



The company earns a return equal to its pre-tax weighted-average cost of capital on permanent capital structure for payments under new clean, renewable, or energy storage PPAs with non-affiliated entities.

Consumers will continue to competitively bid new capacity and energy resources, ensuring a balanced portfolio of intermittent renewables and dispatchable clean resources. Any resulting contracts are subject to MPSC approval. Through these integrated plans, Consumers is advancing Michigan’s clean energy transition while maintaining system reliability, affordability, and regulatory compliance.

J.H. Campbell Emergency Orders: In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. Subsequently, the

U.S. Secretary of Energy issued two additional emergency orders for 90 days each, ultimately requiring continued operation of J.H. Campbell through February 17, 2026. These orders stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and DOE regulations, the orders authorize Consumers to obtain cost recovery at FERC.

As directed, Consumers has continued to make J.H. Campbell available in the MISO market and, in June 2025, filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. In August 2025, FERC granted Consumers' complaint and ordered MISO to revise its tariff accordingly. MISO submitted a compliance filing with FERC in September 2025, and FERC approval of the compliance filing remains pending. For additional discussion of this FERC proceeding and Consumers' request for recovery, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Following the May 2025 emergency order, several third-party stakeholders, including the Michigan Attorney General, the Organization of MISO States, and a group of environmental and public interest groups, asked the U.S. Secretary of Energy to reconsider the May 2025 emergency order. In July 2025, after the U.S. Secretary of Energy took no action on those requests, several parties filed petitions for review of the May 2025 emergency order in federal court. The requests for rehearing were subsequently denied, and similar challenges to the August and November 2025 orders are underway. The U.S. Secretary of Energy may issue more orders to require the continued operation of J.H. Campbell. While the timing and content of future orders and the outcome of third-party legal challenges are not yet known, Consumers is committed to pursuing cost recovery as provided for under applicable laws, orders, and proceedings.

Electric Customer Deliveries and Revenue: Consumers' electric customer deliveries are seasonal and largely dependent on Michigan's economy. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment. In addition, Consumers' electric rates, which follow a seasonal rate design, are higher in the summer months than in the remaining months of the year. Each year in June, electric residential customers transition to a summer peak time-of-use rate that allows them to take advantage of lower-cost energy during off-peak times during the summer months. Thus, customers can reduce their electric bills by shifting their consumption from on-peak to off-peak times.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2025. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- energy conservation measures and results of energy waste reduction programs
- weather fluctuations
- Michigan's economic conditions, including data center expansion; utilization, expansion, or contraction of large commercial and industrial facilities; economic development; population trends; electric vehicle adoption; and housing activity

Electric ROA: Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers' sales, with certain exceptions. At December 31, 2025, electric deliveries under the ROA program were at the 10-percent limit. Fewer than 300 of Consumers' electric customers purchased electric generation service under the ROA program.

In 2016, Michigan law established a path to ensure that forward capacity is secured for all electric customers in Michigan, including customers served by alternative electric suppliers under ROA. The law also authorized the MPSC to ensure that alternative electric suppliers have procured enough capacity to cover their anticipated capacity requirements for the four-year forward period. In 2017, the MPSC issued an order establishing a state reliability mechanism for Consumers. Under this mechanism, if an alternative electric supplier does not demonstrate that it has procured its capacity requirements for the four-year forward period, its customers will pay a set charge to the utility for capacity that is not provided by the alternative electric supplier.

During 2017, the MPSC issued orders finding that it has statutory authority to determine and implement a local clearing requirement, which requires all electric suppliers to demonstrate that a portion of the capacity used to serve customers is located in the MISO footprint in Michigan's Lower Peninsula. In 2020, the Michigan Supreme Court affirmed the MPSC's statutory authority to implement a local clearing requirement on individual electric providers.

In 2020, ABATE and another intervenor filed a complaint against the MPSC in the U.S. District Court for the Eastern District of Michigan challenging the constitutionality of a local clearing requirement. The complaint requested the federal court to issue a permanent injunction prohibiting the MPSC from implementing a local clearing requirement on individual electric providers. In 2023, the U.S. District Court for the Eastern District of Michigan dismissed the complaint. ABATE and the other intervenor filed a claim of appeal of the Eastern District Court's decision with the U.S. Court of Appeals for the Sixth Circuit.

In January 2025, the Sixth Circuit Court of Appeals issued an opinion finding that the MPSC's imposition of a local clearing requirement on individual electric suppliers would discriminate against interstate commerce. The Court of Appeals remanded to the District Court for a determination of whether the local clearing requirement discriminated against interstate commerce and whether the MPSC's regulation survives a strict scrutiny standard, which depends on a determination of whether the local clearing requirement is the only means of achieving the state's goal of securing reliable energy supply. In January 2025, Consumers filed a petition for rehearing and en banc review with the Sixth Circuit Court of Appeals, requesting the Court to reconsider and reverse the panel's opinion. In February 2025, the Sixth Circuit Court of Appeals issued an order denying Consumers' petition for rehearing and en banc review. The case has therefore been remanded to the District Court for the Eastern District of Michigan for consideration of whether the MPSC's local clearing requirement meets the strict scrutiny standard pursuant to the Court of Appeals' decision. The remanded proceeding has begun at the Eastern District Court; there is no deadline for decision.

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, for which Consumers filed in October 2025. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At December 31, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current

hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

Electric Rate Matters: Rate matters are critical to Consumers’ electric utility business. For additional details on rate matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

MPSC Distribution System Audit: In 2022, the MPSC ordered the state’s two largest electric utilities, including Consumers, to report on their compliance with regulations and past MPSC orders governing the utilities’ response to outages and downed lines. Consumers responded to the MPSC’s order as directed.

Additionally, as directed by the MPSC, the MPSC Staff engaged a third-party auditor to review all equipment and operations of the two utilities’ distribution systems. In September 2024, the MPSC Staff released the third-party auditor’s final report on its audit of Consumers’ distribution system. The report included several recommendations to improve Consumers’ distribution system and associated processes and procedures. Consumers filed a response to the audit report in November 2024. In June 2025, the MPSC issued an order adopting the audit’s findings and recommendations. Consumers is committed to working with the MPSC to continue improving electric reliability and safety in Michigan.

Performance-based Financial Incentives/Disincentives Mechanism: In February 2025, the MPSC issued an order establishing a mechanism through which the state’s largest electric utilities, including Consumers, could realize up to \$10 million each in incentives or penalties annually for meeting or failing to meet reliability benchmarks, beginning in 2026. As directed, Consumers filed proposed company-specific baseline metrics for the performance mechanism in April 2025; the MPSC approved Consumers’ proposed metrics in December 2025.

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of \$460 million, made up of two components. First, Consumers requested a \$436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a \$24 million surcharge for the recovery of distribution investments made during the 12 months ended February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders.

In October 2025, Consumers revised its requested increase to \$447 million. Presented in the following table are the components of the revised requested increase in revenue:

	<i>In Millions</i>
Projected 12-Month Period Ending April 30	2027
Investment in rate base	\$ 192
Operating and maintenance costs	157
Cost of capital	67
Sales and other revenue	7
Subtotal	\$ 423
Surcharge	24
Total	\$ 447

The MPSC must issue a final order in this case before or in April 2026.

Large-load Tariff: In November 2025, the MPSC approved changes to Consumers' standard large-customer tariff to govern service for new large electricity users such as data centers. Consumers sought these changes to protect existing customers. The changes apply to customers with a minimum service threshold of 100 MW and require a minimum 15-year contract (beyond the construction period), an 80-percent minimum demand billing obligation, upfront fees, and strong collateral and exit-fee protections to ensure these large customers fully cover their own costs of service and do not shift risk or costs to existing customers. Each large-load contract must receive MPSC approval before taking effect. The MPSC also directed Consumers to present multiple cost-allocation and rate-design options before its next rate case to ensure that large-load customers pay their fair share of system costs going forward.

Depreciation Rate Case: In December 2025, Consumers filed a depreciation case related to its electric and common utility property. In this case, Consumers requested to increase depreciation expense, and its recovery of that expense of \$34 million annually based on December 31, 2024 balances.

Retention Incentive Program: The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. As a result, Consumers has implemented retention measures to ensure appropriate staffing levels and expects to incur up to \$4 million during each 90-day emergency order period. Consumers will seek recovery of these retention costs from FERC, consistent with rate recovery sought for other costs of complying with the emergency orders. For additional details on this program, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 20, Exit Activities and Asset Sales. For additional details on the emergency orders, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Electric Environmental Outlook: Consumers' electric operations are subject to various federal, state, and local environmental laws and regulations. Consumers estimates that it will incur capital expenditures of \$245 million from 2026 through 2030 to continue to comply with RCRA, the Clean Air Act, and numerous other environmental regulations. Consumers expects to recover these costs in customer rates, but cannot guarantee this result. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' electric utility.

MATS, emission standards for electric generating units published by the EPA based on Section 112 of the Clean Air Act, continue to apply to Consumers. In June 2025, the EPA issued a proposed rule to repeal changes made to the MATS rule in 2024. The company has complied, and continues to comply, with the MATS regulation and both the 2024 and proposed 2025 versions of MATS have minimal impacts on Consumers' electric generating units. Consumers does not expect MATS to materially impact its environmental strategy.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. Consumers complies with this regulation and expects it to have minimal financial and operational impact in the near and/or long term.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify power plants and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment. Additionally, a December 2025 court decision vacated the EPA's 2023 redesignation of a seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. None of Consumers'

fossil-fuel-fired generating units are located in these areas. Consumers will continue to monitor the impact of the recent court decision on the seven-county area in southeast Michigan, including resulting agency actions, but does not anticipate it will have any impact on Consumers' generating assets.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. Consumers does not have any fossil-fuel-fired generating assets in these counties and therefore does not expect this rule to have significant impacts on its existing generating assets or its clean energy strategy. Consumers will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to its generating assets.

In January 2026, the EPA published a final rule amending new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NO_x. This final rule requires new large simple-cycle turbine units with higher capacity factors to install control equipment for NO_x emissions. Consumers is evaluating this rule to determine its impact.

Consumers continues to evaluate these rules in conjunction with other EPA and EGLE rulemakings, litigation, executive orders, treaties, and congressional actions. This evaluation could result in:

- a change in Consumers' fuel mix
- changes in the types of generating units Consumers may purchase or build in the future
- changes in how certain units are operated, including the installation of additional emission control equipment
- the retirement, mothballing, extended operation, or repowering with an alternative fuel of some of Consumers' generating units
- changes in Consumers' environmental compliance costs
- the purchase or sale of emission allowances

Greenhouse Gases: There have been numerous legislative, executive, and regulatory initiatives at the state, regional, national, and international levels that involve the potential regulation and reporting of greenhouse gases. Consumers continues to monitor and comment on these initiatives, as appropriate.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources, including Consumers' electric generation sites and distribution equipment. Reporting of carbon dioxide to the EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program, which includes Consumers' fossil-fuel-fired electric generation. This change could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Consumers does not expect these proposed changes will have a significant impact on its existing gas- and oil-fueled steam electric generating assets. Consumers will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

Increased frequency or intensity of severe or extreme weather events, including those due to climate change, could materially impact Consumers' facilities, energy sales, and results of operations. Consumers is unable to predict these events; however, Consumers evaluates the potential physical impacts of climate

change on its operations, including increased frequency or intensity of storm activity; increased precipitation; increased temperature; and changes in lake and river levels. Consumers released a report addressing the physical risks of climate change on its infrastructure in 2022. Consumers is taking steps to mitigate these risks as appropriate.

While Consumers cannot predict the outcome of changes in U.S. policy or of other legislative, executive, or regulatory initiatives involving the potential regulation or reporting of greenhouse gases, it intends to move forward with its compliance with Michigan's clean energy requirements, its own sustainability goals, and its emphasis on reliable and resilient electric supply. Litigation, international treaties, executive orders, federal laws and regulations (including regulations by the EPA), and state laws and regulations, if enacted or ratified, could ultimately impact Consumers. Consumers may be required to:

- replace equipment
- install additional emission control equipment
- purchase emission allowances or credits (including potential greenhouse gas offset credits)
- curtail operations or modify existing facility retirement schedules
- arrange for alternative sources of supply
- purchase or build facilities that generate fewer emissions
- mothball, sell, or retire facilities that generate certain emissions
- pursue energy efficiency or demand response measures more swiftly
- take other steps to manage, sequester, or lower the emission of greenhouse gases

Although associated capital or operating costs relating to greenhouse gas regulation or legislation could be material and cost recovery cannot be assured, Consumers expects to recover these costs in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

CCRs: In 2015, the EPA published a rule regulating CCRs under RCRA. This rule adopts minimum standards for the disposal of non-hazardous CCRs in CCR landfills and surface impoundments and criteria for the beneficial use of CCRs. The rule also sets out conditions under which some CCR units would be forced to cease receiving CCRs and related process water and to initiate closure. Due to continued litigation, many aspects of the rule have been remanded to the EPA, resulting in more proposed and final rules.

In May 2024, the EPA finalized a rule regulating legacy CCR surface impoundments and CCR management units in response to litigation that exempted inactive impoundments at inactive facilities from the 2015 CCR rule. The new rule adopts minimum standards for impoundments at electric generating facilities that became inactive before the 2015 CCR rule's effective date. During 2024, owners and operators were required to assess whether an inactive facility contains a legacy surface impoundment and then, for identified locations, proceed with the compliance schedule.

Additionally, the EPA established groundwater monitoring, corrective action, closure, and post-closure care requirements for CCR surface impoundments and landfills closed prior to the effective date of the 2015 CCR rule, but that do not meet the closure technical and performance standards of the May 2024 rule. These include inactive CCR landfills that were previously exempted from regulation but that are now considered CCR management units. Owners are required to conduct an evaluation at active facilities or any inactive facilities with at least one legacy impoundment to identify CCR management units and determine an appropriate course of action (closure, groundwater treatment, etc.) for each identified unit according to established compliance milestone schedules. In February 2026, the EPA issued a final rule extending the compliance milestone schedule for CCR management units. This extension does not have a material impact on Consumers' compliance strategy.

Separately, Congress passed legislation in 2016 allowing participating states to develop permitting programs for CCRs under RCRA Subtitle D. The EPA was granted authority to review these permitting programs to determine if permits issued under the proposed program would be as protective as the federal rule. Once approved, permits issued from an authorized state would serve as the basis for compliance, replacing the requirement to self-certify each aspect of the 2015 CCR rule.

Consumers, with agreement from EGLE, completed the work necessary to initiate closure by excavating CCRs or placing a final cover over each of its relevant CCR units prior to the closure initiation deadline set forth in the 2015 CCR rule. Consumers has historically been authorized to recover in electric rates costs related to coal ash disposal sites that supported power generation. Consumers completed an assessment of inactive facilities as required by the 2024 CCR rule, and did not identify any legacy impoundments. Consumers is continuing evaluations related to CCR management units and 2024 CCR rule impacts on the state permit program.

Water: Multiple water-related regulations apply, or may apply, to Consumers.

The EPA regulates cooling water intake systems of existing electric generating plants under Section 316(b) of the Clean Water Act. The rules seek to reduce alleged harmful impacts on aquatic organisms, such as fish. In 2018, Consumers submitted to EGLE studies and recommended plans to comply with Section 316(b) for its coal-fueled units but has not yet received final approval.

The EPA also regulates the discharge of wastewater through its effluent limitation guidelines for steam electric generating plants. Consumers has submitted the appropriate notices of planned participation in compliance with this rule. Consumers has also submitted timely NPDES permit applications and will be working with EGLE to incorporate applicable provisions during the permit renewal process.

Many of Consumers' facilities maintain NPDES permits, which are vital to the facilities' operations. Consumers applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Protected Wildlife: Multiple regulations apply, or may apply, to Consumers relating to protected species and habitats.

Statutes like the federal Endangered Species Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act of 1940 and changes to permitting may impact operations at Consumers' facilities. In February 2024, the U.S. Fish and Wildlife Service published a final rule providing for bald eagle general permits for qualifying wind farms and electric distribution systems. Consumers has received, or is pursuing, bald eagle general permits for all its wind farms. While any resulting permitting and monitoring fees and/or restrictions on operations could impact Consumers' existing and future operations, Consumers does not expect any material changes to its environmental strategy or Electric Supply Plan as a result of this rule.

Additionally, Consumers regularly monitors proposed changes to the listing status of several species within its operational area. A change in species listed under the Endangered Species Act, or under Michigan's equivalent law, may impact Consumers' costs to mitigate its impact on protected species and habitats at certain existing facilities as well as siting choices for new facilities.

Other Matters: Other electric environmental matters could have a material impact on Consumers' outlook. For additional details on other electric environmental matters, see Item 8. Financial Statements

and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Consumers Electric Utility Contingencies—Electric Environmental Matters.

Consumers Gas Utility Outlook and Uncertainties

Gas Deliveries: Consumers’ gas customer deliveries are seasonal. The peak demand for natural gas occurs in the winter due to colder temperatures and the resulting use of natural gas as heating fuel.

Over the next five years, Consumers expects weather-normalized gas deliveries to remain stable relative to 2025. This outlook reflects modest growth in gas demand, offset by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- weather fluctuations
- use by power producers
- availability and development of renewable energy sources
- gas price changes
- Michigan’s economic conditions, including population trends and housing activity
- the price or demand of competing energy sources or fuels
- energy efficiency and conservation impacts

Gas Rate Matters: Rate matters are critical to Consumers’ gas utility business. For additional details on rate matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

2025 Gas Rate Case: In December 2025, Consumers filed an application with the MPSC seeking an annual rate increase of \$240 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2027.

Presented in the following table are the components of the requested increase in revenue:

	<i>In Millions</i>
Projected 12-Month Period Ending October 31	2027
Investment in rate base	\$ 108
Operating and maintenance costs	65
Cost of capital	66
Sales/gross margin	1
Total	\$ 240

The MPSC must issue a final order in this case before or in October 2026.

Gas Pipeline and Storage Integrity and Safety: Consumers’ gas operations are governed by federal and state pipeline safety rules, and there are robust processes and procedures in place to maintain compliance with these regulations. The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration has published various rules that revise federal safety standards for gas transmission pipelines and underground storage facilities. Consumers has implemented measures to achieve compliance with the revised rules. There are also proposed rules expanding requirements for gas safety, although these rules are subject to reconsideration by the current administration. Under the proposed rules, Consumers will incur increased capital and increased operating and maintenance costs to install and remediate pipelines and to expand inspections, maintenance, and monitoring of existing pipelines and storage facilities.

Although associated capital or operating and maintenance costs relating to these regulations could be material and cost recovery cannot be assured, Consumers expects to recover such costs in rates consistent with the recovery of other reasonable costs of complying with laws and regulations.

Gas Environmental Outlook: Consumers expects to incur response activity costs at a number of sites, including 23 former MGP sites. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Consumers Gas Utility Contingencies.

Consumers' gas operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' gas utility.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify natural gas compressor stations and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment, which has more stringent requirements. One of Consumers' compressor stations is in a serious ozone nonattainment area. Consequently, Consumers has initiated plans to retrofit equipment at this compressor station to lower NO_x emissions.

Additionally, a December 2025 court decision vacated the EPA's 2023 redesignation of the seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. Four of Consumers' compressor stations are located in these counties, with one station having assets that may be impacted by the redesignation change. Consumers will continue to monitor the recent court decision's impact on the seven-county area in southeast Michigan, including resulting agency actions, and the potential impacts to compressor station assets.

Consumers will continue to monitor NAAQS rulemakings and litigation, and evaluate potential impacts to its compressor stations and other applicable natural gas storage and delivery assets.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. Consumers has one compressor station located in Wayne County and will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to the natural gas compressor station assets.

Greenhouse Gases: Some interest exists at the various levels of government in regulating greenhouse gases or their sources. Future regulations, if adopted, may involve requirements to reduce methane emissions from Consumers' gas utility operations and carbon dioxide emissions from customer use of natural gas. Consumers will continue to monitor such potential rules for impacts.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by removing the natural gas distribution segment from the reporting obligations under the petroleum and natural gas source category, and proposed to delay the reporting obligations until 2034 for the remaining sources in this category. If this proposal is finalized as proposed, it could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

Consumers is making voluntary efforts to reduce its gas utility's methane emissions. Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery

system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. To date, Consumers has reduced methane emissions by more than 40 percent.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers' Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers, outlines ways in which Consumers can make early progress toward these goals in a cost-effective manner, including energy waste reduction, carbon offsets, and renewable natural gas supply.

Consumers has already initiated work in these key areas by continuing to expand its energy waste reduction targets and by offering gas customers the ability to offset their carbon footprint associated with natural gas use by purchasing renewable natural gas and/or carbon credits associated with Michigan forest preservation. Consumers has renewable natural gas facilities under construction scheduled for commercial operation in 2026 and is monitoring regulatory developments and market conditions closely as part of its ongoing evaluation of the projects. As part of this evaluation, two early-phase renewable natural gas development projects have been paused indefinitely, and Consumers recognized an impairment charge of \$15 million related to these projects in 2025. Consumers is evaluating and monitoring newer technologies to determine their role in achieving Consumers' interim and long-term net-zero goals, including biofuels, geothermal, synthetic methane, carbon capture sequestration systems, and other innovative technologies.

NorthStar Clean Energy Outlook and Uncertainties

CMS Energy's primary focus with respect to its NorthStar Clean Energy businesses is to maximize the value of generating assets representing 1,665 MW of capacity, and to pursue opportunities for the development of renewable generation projects, including leveraging strategic partnerships and available tax incentives.

In December 2025, NorthStar Clean Energy sold a Class A membership interest in BG Solar Holdings to a tax equity investor. BG Solar Holdings is the holding company of a 200-MW solar generation project being constructed in Branch County, Michigan. All of the project's nameplate capacity has been committed under a 15-year renewable energy purchase agreement. The tax equity investor contributed \$15 million and recognized a deemed contribution of \$35 million associated with BG Solar Holdings' sale of investment tax credits related to a portion of the project placed into service for tax purposes in 2025. The tax equity investor will contribute additional amounts upon commercial operation of the project in 2026.

NorthStar Clean Energy retained a Class B membership interest in BG Solar Holdings. Earnings, tax attributes, and cash flows generated by BG Solar Holdings will be allocated among and distributed to the membership classes in accordance with the ratios specified in the associated limited liability company operating agreement; these ratios change over time and are not representative of the ownership interest percentages of each membership class. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 19, Variable Interest Entities.

Trends, uncertainties, and other matters related to NorthStar Clean Energy that could have a material impact on CMS Energy's consolidated income, cash flows, or financial position include:

- investment in and financial benefits received from renewable energy and energy storage projects, including changes to tax and trade policy
- delays or difficulties in financing, constructing, and developing projects, including those arising from the performance of contractors, suppliers, or other counterparties
- changes in energy, capacity, and other commodity prices
- severe weather events and climate change associated with increasing levels of greenhouse gases
- changes in various environmental laws, regulations, principles, or practices, or in their interpretation
- indemnity obligations assumed in connection with ownership interests in facilities that involve tax equity financing
- representations, warranties, and indemnities provided in connection with sales of assets
- delays or difficulties in obtaining environmental permits

For additional details regarding NorthStar Clean Energy's uncertainties, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Guarantees.

NorthStar Clean Energy Environmental Outlook: NorthStar Clean Energy's operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. NorthStar Clean Energy's primary environmental compliance focus includes, but is not limited to, the following matters.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. NorthStar Clean Energy complies with this regulation and expects it to have minimal financial and operational impact in the near and/or long term.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. NorthStar Clean Energy has two fossil-fuel-fired generating units in these counties and therefore will continue to monitor NAAQS rulemaking and litigation to evaluate potential impacts to its generating assets.

In January 2026, the EPA published a final rule amending new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NO_x. This final rule requires new large simple-cycle turbine units with higher capacity factors to install control equipment for NO_x emissions. NorthStar Clean Energy will monitor this rulemaking.

A December 2025 court decision vacated the EPA's 2023 redesignation of the seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. NorthStar Clean Energy has one electric generating station located within this area. NorthStar Clean Energy will continue to monitor the recent court decision's impact on the seven-county area in southeast Michigan, including resulting agency actions, and the potential impacts to compressor station assets.

For additional details regarding the ozone NAAQS, see Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources. Reporting of carbon dioxide to the

EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program. This change could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Neither pathway impacts NorthStar Clean Energy's existing facilities. NorthStar Clean Energy will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

Many of NorthStar Clean Energy's facilities maintain NPDES permits, which are vital to the facilities' operations. NorthStar Clean Energy applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Other Outlook and Uncertainties

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

Litigation: CMS Energy, Consumers, and certain of their subsidiaries are named as parties in various litigation matters, as well as in administrative proceedings before various courts and governmental agencies, arising in the ordinary course of business. For additional details regarding certain legal matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Critical Accounting Estimates

The following information is important to understand CMS Energy's and Consumers' results of operations and financial condition. For additional accounting policies, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 1, Significant Accounting Policies.

In the preparation of CMS Energy's and Consumers' consolidated financial statements, estimates and assumptions are used that may affect reported amounts and disclosures. CMS Energy and Consumers use accounting estimates for asset valuations, unbilled revenue, depreciation, amortization, financial and derivative instruments, employee benefits, stock-based compensation, the effects of regulation, indemnities, contingencies, and AROs. Actual results may differ from estimated results due to changes in the regulatory environment, regulatory decisions, lawsuits, competition, and other factors. CMS Energy and Consumers consider all relevant factors in making these assessments.

Accounting for the Effects of Industry Regulation: Because Consumers has regulated operations, it uses regulatory accounting to recognize the effects of the regulators' decisions on its financial statements. Consumers continually assesses whether future recovery of its regulatory assets is probable by considering communications and experience with its regulators and changes in the regulatory environment. If Consumers determined that recovery of a regulatory asset were not probable, Consumers would be required to write off the asset and immediately recognize the expense in earnings. For additional information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Contingencies: CMS Energy and Consumers make judgments regarding the future outcome of various matters that give rise to contingent liabilities. For such matters, they record liabilities when they are considered probable and reasonably estimable, based on all available information. In particular, CMS Energy and Consumers are participating in various environmental remediation projects for which they have recorded liabilities. The recorded amounts represent estimates that may take into account such considerations as the number of sites, the anticipated scope, cost, and timing of remediation work, the available technology, applicable regulations, and the requirements of governmental authorities. For remediation projects in which the timing of estimated expenditures is considered reliably determinable, CMS Energy and Consumers record the liability at its net present value, using a discount rate equal to the interest rate on monetary assets that are essentially risk-free and have maturities comparable to that of the environmental liability. The amount recorded for any contingency may differ from actual costs incurred when the contingency is resolved. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

Income Taxes: The amount of income taxes paid by CMS Energy is subject to ongoing audits by federal, state, and foreign tax authorities, which can result in proposed assessments. An estimate of the potential outcome of any uncertain tax issue is highly judgmental. CMS Energy believes adequate reserves have been provided for these exposures; however, future results may include favorable or unfavorable adjustments to the estimated tax liabilities in the period the assessments are made or resolved or when statutes of limitation on potential assessments expire. Additionally, CMS Energy's judgment as to the ability to recover its deferred tax assets may change. CMS Energy believes the valuation allowances related to its deferred tax assets are adequate, but future results may include favorable or unfavorable adjustments. As a result, CMS Energy's effective tax rate may fluctuate significantly over time. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

Pension and OPEB: CMS Energy and Consumers provide retirement pension benefits to certain employees under non-contributory DB Pension Plans, and they provide postretirement health and life benefits to qualifying retired employees under an OPEB Plan.

CMS Energy and Consumers record liabilities for pension and OPEB on their consolidated balance sheets at the present value of the future obligations, net of any plan assets. The calculation of the liabilities and associated expenses requires the expertise of actuaries, and requires many assumptions, including:

- life expectancies
- discount rates
- expected long-term rate of return on plan assets
- rate of compensation increases
- expected health care costs

A change in these assumptions could change significantly CMS Energy's and Consumers' recorded liabilities and associated expenses.

Presented in the following table are estimates of credits and cash contributions through 2028 for the DB Pension Plans and OPEB Plan. Actual future costs, credits, and contributions will depend on future investment performance, discount rates, and various factors related to the participants of the DB Pension Plans and OPEB Plan. CMS Energy and Consumers will, at a minimum, contribute to the plans as needed to comply with federal funding requirements.

	<i>In Millions</i>			
	DB Pension Plans		OPEB Plan	
	Credit	Contribution	Credit	Contribution
CMS Energy, including Consumers				
2026	\$ (86)	\$ —	\$ (109)	\$ —
2027	(87)	—	(99)	—
2028	(100)	—	(92)	—
Consumers¹				
2026	\$ (81)	\$ —	\$ (101)	\$ —
2027	(81)	—	(91)	—
2028	(94)	—	(84)	—

¹ Consumers' pension and OPEB costs are recoverable through its general ratemaking process.

Lowering the expected long-term rate of return on the assets of the DB Pension Plans by 25 basis points would increase estimated pension cost for 2026 by \$8 million for both CMS Energy and Consumers. Lowering the PBO discount rates by 25 basis points would decrease estimated pension cost for 2026 by \$1 million for both CMS Energy and Consumers. Pension and OPEB costs above or below the amounts used to set existing rates will be deferred as a regulatory asset or liability in accordance with Consumers' postretirement benefits expense deferral mechanism; for more information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Pension and OPEB plan assets are accounted for and disclosed at fair value. Fair value measurements incorporate assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. Development of these assumptions may require judgment.

For additional details on postretirement benefits, including the fair value measurements for the assets of the DB Pension Plans and OPEB Plan, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 11, Retirement Benefits.

Unbilled Revenues: Consumers' customers are billed monthly in cycles having billing dates that do not generally coincide with the end of a calendar month. This results in customers having received electricity or natural gas that they have not been billed for as of the month-end. Consumers estimates its unbilled revenues by applying an average billed rate to total unbilled deliveries for each customer class. Consumers records unbilled revenues as accounts receivable and accrued revenue on its consolidated balance sheet. For additional information on unbilled revenues, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 15, Revenue.

New Accounting Standards

For details regarding new accounting standards issued but not yet effective, See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 2, New Accounting Standards.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

CMS Energy and Consumers are exposed to market risks including, but not limited to, changes in interest rates, commodity prices, and investment security prices. They may enter into various risk management contracts to mitigate exposure to these risks, including swaps, options, futures, and forward contracts. CMS Energy and Consumers enter into these contracts using established policies and procedures, under the direction of an executive oversight committee consisting of certain officers and a risk committee consisting of those and other officers and business managers.

The following risk sensitivity illustrates the potential loss in fair value, cash flows, or future earnings from financial instruments, assuming a hypothetical adverse change in market rates or prices of 10 percent. Potential losses could exceed the amounts shown in the sensitivity analyses if changes in market rates or prices were to exceed 10 percent.

Long-term Debt: CMS Energy and Consumers are exposed to interest-rate risk resulting from issuing fixed-rate and variable-rate debt instruments. CMS Energy and Consumers use a combination of these instruments, and may also enter into interest-rate swap agreements, in order to manage this risk and to achieve a reasonable cost of capital.

Presented in the following table is a sensitivity analysis of interest-rate risk on CMS Energy’s and Consumers’ debt instruments (assuming an adverse change in market interest rates of 10 percent):

	<i>In Millions</i>	
December 31	2025	2024
<i>Fixed-rate financing—potential loss in fair value</i>		
CMS Energy, including Consumers	\$ 792	\$ 717
Consumers	535	543

The fair value losses in the above table could be realized only if CMS Energy and Consumers transferred all of their fixed-rate financing to other creditors. The annual earnings exposure related to variable-rate financing was immaterial for both CMS Energy and Consumers at December 31, 2025 and 2024, assuming an adverse change in market interest rates of 10 percent. For additional details on financial instruments see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 7, Financial Instruments.

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Item 8. Financial Statements and Supplementary Data

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CMS Energy Corporation

Consolidated Statements of Income

In Millions, Except Per Share Amounts

Years Ended December 31	2025	2024	2023
Operating Revenue	\$ 8,539	\$ 7,515	\$ 7,462
Operating Expenses			
Fuel for electric generation	657	624	561
Purchased and interchange power	1,706	1,333	1,375
Purchased power – related parties	94	71	75
Cost of gas sold	809	640	902
Maintenance and other operating expenses	1,727	1,638	1,687
Depreciation and amortization	1,306	1,240	1,180
General taxes	513	482	447
Total operating expenses	6,812	6,028	6,227
Operating Income	1,727	1,487	1,235
Other Income (Expense)			
Non-operating retirement benefits, net	186	169	180
Other income	151	207	195
Other expense	(27)	(32)	(13)
Total other income	310	344	362
Interest Charges			
Interest on long-term debt	798	700	616
Interest expense – related parties	11	12	12
Other interest expense	(9)	14	18
Allowance for borrowed funds used during construction	(11)	(18)	(3)
Total interest charges	789	708	643
Income Before Income Taxes	1,248	1,123	954
Income Tax Expense	246	176	147
Income From Continuing Operations	1,002	947	807
Income From Discontinued Operations, Net of Tax of \$— for all periods	—	—	1
Net Income	1,002	947	808
Loss Attributable to Noncontrolling Interests	(69)	(56)	(79)
Net Income Attributable to CMS Energy	1,071	1,003	887
Preferred Stock Dividends	10	10	10
Net Income Available to Common Stockholders	\$ 1,061	\$ 993	\$ 877
Basic Earnings Per Average Common Share	\$ 3.53	\$ 3.34	\$ 3.01
Diluted Earnings Per Average Common Share	\$ 3.53	\$ 3.33	\$ 3.01

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consolidated Statements of Comprehensive Income

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Net Income	\$ 1,002	\$ 947	\$ 808
Retirement Benefits Liability			
Net gain arising during the period, net of tax of \$2, \$1, and \$2	4	2	5
Prior service credit adjustment, net of tax of \$— for all periods	—	1	—
Amortization of net actuarial loss, net of tax of \$— for all periods	2	2	2
Amortization of prior service credit, net of tax of \$— for all periods	(1)	—	(1)
Other Comprehensive Income	5	5	6
Comprehensive Income	1,007	952	814
Comprehensive Loss Attributable to Noncontrolling Interests	(69)	(56)	(79)
Comprehensive Income Attributable to CMS Energy	\$ 1,076	\$ 1,008	\$ 893

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consolidated Statements of Cash Flows

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net income	\$ 1,002	\$ 947	\$ 808
<i>Adjustments to reconcile net income to net cash provided by operating activities</i>			
Depreciation and amortization	1,306	1,240	1,180
Deferred income taxes and investment tax credits	202	142	157
Bad debt expense	40	33	34
Postretirement benefits contributions	(16)	(13)	(12)
Other non-cash operating activities and reconciling adjustments	(238)	(241)	(274)
<i>Changes in assets and liabilities</i>			
Accounts receivable and accrued revenue	(251)	(155)	241
Inventories	(28)	164	185
Accounts payable and accrued rate refunds	196	15	(136)
Other current assets and liabilities	78	42	(21)
Other non-current assets and liabilities	(56)	196	147
Net cash provided by operating activities	2,235	2,370	2,309
Cash Flows from Investing Activities			
Capital expenditures (excludes assets placed under finance lease)	(3,824)	(3,018)	(2,407)
Covert Generating Station acquisition	—	—	(812)
Proceeds from sale of ASP business	—	124	—
Cost to retire property and other investing activities	(214)	(160)	(167)
Net cash used in investing activities	(4,038)	(3,054)	(3,386)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	3,609	1,962	3,551
Retirement of debt	(1,150)	(952)	(2,132)
Increase (decrease) in notes payable	(65)	(28)	73
Issuance of common stock	525	286	192
Payment of dividends on common and preferred stock	(663)	(626)	(579)
Proceeds from the sale of membership interests in VIEs	44	—	—
Proceeds from the sale of membership interest in VIE to tax equity investor	15	—	86
Contributions from noncontrolling interests	4	5	6
Distributions to noncontrolling interests	(14)	(12)	(12)
Other financing costs	(65)	(21)	(42)
Net cash provided by financing activities	2,240	614	1,143
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	437	(70)	66
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	178	248	182
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	\$ 615	\$ 178	\$ 248

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Other Cash Flow Activities and Non-cash Investing and Financing Activities			
<i>Cash transactions</i>			
Interest paid (net of amounts capitalized)	\$ 741	\$ 677	\$ 607
Income taxes paid (proceeds from sale of renewable energy tax credits), net	(20)	(69)	15
<i>Non-cash transactions</i>			
Capital expenditures not paid	\$ 662	\$ 517	\$ 265
Deemed contribution from sale of membership interest	35	—	—

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consolidated Balance Sheets

ASSETS

	<i>In Millions</i>	
December 31	2025	2024
Current Assets		
Cash and cash equivalents	\$ 509	\$ 103
Restricted cash and cash equivalents	106	75
Accounts receivable and accrued revenue, less allowance of \$27 in 2025 and \$23 in 2024	1,306	1,049
Accounts receivable – related parties	17	14
<i>Inventories at average cost</i>		
Gas in underground storage	427	435
Materials and supplies	329	299
Generating plant fuel stock	35	35
Deferred property taxes	479	448
Regulatory assets	104	229
Prepayments and other current assets	160	103
Total current assets	3,472	2,790
Plant, Property, and Equipment		
Plant, property, and equipment, gross	37,763	34,932
Less accumulated depreciation and amortization	10,135	9,569
Plant, property, and equipment, net	27,628	25,363
Construction work in progress	3,052	2,098
Total plant, property, and equipment	30,680	27,461
Other Non-current Assets		
Regulatory assets	3,355	3,569
Accounts receivable	18	20
Investments	61	69
Postretirement benefits	1,957	1,627
Other	398	384
Total other non-current assets	5,789	5,669
Total Assets	\$ 39,941	\$ 35,920

LIABILITIES AND EQUITY

	<i>In Millions</i>	
December 31	2025	2024
Current Liabilities		
Current portion of long-term debt and finance leases	\$ 956	\$ 1,195
Notes payable	—	65
Accounts payable	1,395	1,085
Accounts payable – related parties	9	8
Accrued rate refunds	28	38
Accrued interest	182	156
Accrued taxes	708	654
Regulatory liabilities	85	111
Other current liabilities	185	209
Total current liabilities	3,548	3,521
Non-current Liabilities		
Long-term debt	17,807	15,194
Non-current portion of finance leases	135	112
Regulatory liabilities	4,091	4,067
Postretirement benefits	95	96
AROs	792	728
Deferred investment tax credit	118	122
Deferred income taxes	3,252	2,925
Other non-current liabilities	392	407
Total non-current liabilities	26,682	23,651
Commitments and Contingencies (Notes 3 and 4)		
Equity		
<i>Common stockholders' equity</i>		
Common stock, authorized 350.0 shares in both periods; outstanding 306.4 shares in 2025 and 298.8 shares in 2024	3	3
Other paid-in capital	6,510	6,009
Accumulated other comprehensive loss	(36)	(41)
Retained earnings	2,443	2,035
Total common stockholders' equity	8,920	8,006
Cumulative redeemable perpetual preferred stock, Series C, authorized 9.2 depositary shares; outstanding 9.2 depositary shares in both periods	224	224
Total stockholders' equity	9,144	8,230
Noncontrolling interests	567	518
Total equity	9,711	8,748
Total Liabilities and Equity	\$ 39,941	\$ 35,920

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consolidated Statements of Changes in Equity

In Millions, Except Number of Shares in Thousands and Per Share Amounts

Years Ended December 31	Number of Shares			2025	2024	2023
	2025	2024	2023			
Total Equity at Beginning of Period				\$ 8,748	\$ 8,125	\$ 7,595
Common Stock						
At beginning and end of period				3	3	3
Other Paid-in Capital						
At beginning of period	298,790	294,440	291,268	6,009	5,705	5,490
Common stock issued	7,839	4,673	3,355	548	315	222
Common stock repurchased	(181)	(181)	(119)	(13)	(11)	(7)
Common stock reacquired	(39)	(142)	(64)	—	—	—
Adjustment for sale of membership interests in VIEs				(34)	—	—
At end of period	306,409	298,790	294,440	6,510	6,009	5,705
Accumulated Other Comprehensive Loss						
<i>Retirement benefits liability</i>						
At beginning of period				(41)	(46)	(52)
Net gain arising during the period				4	2	5
Prior service credit adjustment				—	1	—
Amortization of net actuarial loss				2	2	2
Amortization of prior service credit				(1)	—	(1)
At end of period				(36)	(41)	(46)
Retained Earnings						
At beginning of period				2,035	1,658	1,350
Net income attributable to CMS Energy				1,071	1,003	887
Dividends declared on common stock				(653)	(616)	(569)
Dividends declared on preferred stock				(10)	(10)	(10)
At end of period				2,443	2,035	1,658
Cumulative Redeemable Perpetual Preferred Stock, Series C						
At beginning and end of period				224	224	224
Noncontrolling Interests						
At beginning of period				518	581	580
Sale of membership interests in VIEs				78	—	—
Sale of membership interest in VIE to tax equity investor				50	—	86
Contributions from noncontrolling interests				4	5	6
Distributions to noncontrolling interests				(14)	(12)	(12)
Loss attributable to noncontrolling interests				(69)	(56)	(79)
At end of period				567	518	581
Total Equity at End of Period				\$ 9,711	\$ 8,748	\$ 8,125
Dividends declared per common share				\$ 2.170	\$ 2.060	\$ 1.950
Dividends declared per preferred stock Series C depository share				\$ 1.050	\$ 1.050	\$ 1.050

The accompanying notes are an integral part of these statements.

Consumers Energy Company

Consolidated Statements of Income

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Operating Revenue	\$ 8,132	\$ 7,200	\$ 7,166
Operating Expenses			
Fuel for electric generation	535	511	435
Purchased and interchange power	1,564	1,285	1,331
Purchased power – related parties	94	71	75
Cost of gas sold	803	637	897
Maintenance and other operating expenses	1,614	1,520	1,586
Depreciation and amortization	1,254	1,191	1,137
General taxes	499	470	437
Total operating expenses	6,363	5,685	5,898
Operating Income	1,769	1,515	1,268
Other Income (Expense)			
Non-operating retirement benefits, net	175	157	171
Other income	55	85	49
Other expense	(22)	(30)	(12)
Total other income	208	212	208
Interest Charges			
Interest on long-term debt	521	488	415
Interest expense – related parties	41	31	20
Other interest expense	8	12	16
Allowance for borrowed funds used during construction	(10)	(13)	(3)
Total interest charges	560	518	448
Income Before Income Taxes	1,417	1,209	1,028
Income Tax Expense	288	200	161
Net Income	1,129	1,009	867
Preferred Stock Dividends	2	2	2
Net Income Available to Common Stockholder	\$ 1,127	\$ 1,007	\$ 865

The accompanying notes are an integral part of these statements.

Consumers Energy Company

Consolidated Statements of Comprehensive Income

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Net Income	\$ 1,129	\$ 1,009	\$ 867
Retirement Benefits Liability			
Net gain (loss) arising during the period, net of tax of \$(1), \$1, and \$—	(2)	3	(1)
Amortization of net actuarial loss, net of tax of \$— for all periods	—	1	1
Other Comprehensive Income (Loss)	(2)	4	—
Comprehensive Income	\$ 1,127	\$ 1,013	\$ 867

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Statements of Cash Flows

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net income	\$ 1,129	\$ 1,009	\$ 867
<i>Adjustments to reconcile net income to net cash provided by operating activities</i>			
Depreciation and amortization	1,254	1,191	1,137
Deferred income taxes and investment tax credits	48	115	156
Bad debt expense	40	33	34
Postretirement benefits contributions	(10)	(9)	(9)
Other non-cash operating activities and reconciling adjustments	(165)	(137)	(123)
<i>Changes in assets and liabilities</i>			
Accounts and notes receivable and accrued revenue	(235)	(153)	219
Inventories	(24)	164	186
Accounts payable and accrued rate refunds	187	19	(127)
Other current assets and liabilities	104	75	(35)
Other non-current assets and liabilities	(90)	139	125
Net cash provided by operating activities	2,238	2,446	2,430
Cash Flows from Investing Activities			
Capital expenditures (excludes assets placed under finance lease)	(3,314)	(2,842)	(2,248)
Covert Generating Station acquisition	—	—	(812)
Proceeds from sale of ASP business	—	124	—
Cost to retire property and other investing activities	(221)	(154)	(141)
Net cash used in investing activities	(3,535)	(2,872)	(3,201)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	1,123	1,297	2,666
Retirement of debt	(115)	(389)	(1,654)
Increase (decrease) in notes payable	(65)	(28)	73
Increase (decrease) in notes payable – related parties	340	—	(75)
Stockholder contribution	920	735	475
Return of stockholder contribution	—	(320)	—
Payment of dividends on common and preferred stock	(900)	(797)	(697)
Other financing costs	(14)	(9)	(21)
Net cash provided by financing activities	1,289	489	767
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	(8)	63	(4)
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	119	56	60
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	\$ 111	\$ 119	\$ 56

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Other Cash Flow Activities and Non-cash Investing and Financing Activities			
<i>Cash transactions</i>			
Interest paid (net of amounts capitalized)	\$ 526	\$ 484	\$ 417
Income taxes paid (proceeds from sale of renewable energy tax credits), net	161	(19)	31
<i>Non-cash transactions</i>			
Capital expenditures not paid	\$ 533	\$ 395	\$ 264

The accompanying notes are an integral part of these statements.

Consumers Energy Company

Consolidated Balance Sheets

ASSETS

	<i>In Millions</i>	
December 31	2025	2024
Current Assets		
Cash and cash equivalents	\$ 25	\$ 44
Restricted cash and cash equivalents	86	75
Accounts receivable and accrued revenue, less allowance of \$27 in 2025 and \$23 in 2024	1,210	1,019
Accounts and notes receivable – related parties	15	17
<i>Inventories at average cost</i>		
Gas in underground storage	427	435
Materials and supplies	316	291
Generating plant fuel stock	31	30
Deferred property taxes	479	448
Regulatory assets	104	229
Prepayments and other current assets	132	86
Total current assets	2,825	2,674
Plant, Property, and Equipment		
Plant, property, and equipment, gross	36,120	33,434
Less accumulated depreciation and amortization	9,842	9,310
Plant, property, and equipment, net	26,278	24,124
Construction work in progress	2,354	1,766
Total plant, property, and equipment	28,632	25,890
Other Non-current Assets		
Regulatory assets	3,355	3,569
Accounts receivable	24	26
Accounts and notes receivable – related parties	88	92
Postretirement benefits	1,821	1,514
Other	346	323
Total other non-current assets	5,634	5,524
Total Assets	\$ 37,091	\$ 34,088

LIABILITIES AND EQUITY

	<i>In Millions</i>	
December 31	2025	2024
Current Liabilities		
Current portion of long-term debt and finance leases	\$ 579	\$ 456
Notes payable	—	65
Notes payable – related parties	340	—
Accounts payable	1,229	917
Accounts payable – related parties	14	12
Accrued rate refunds	28	38
Accrued interest	149	130
Accrued taxes	747	678
Regulatory liabilities	85	111
Other current liabilities	163	185
Total current liabilities	3,334	2,592
Non-current Liabilities		
Long-term debt	11,524	10,818
Long-term debt – related parties	1,005	823
Non-current portion of finance leases	81	69
Regulatory liabilities	4,091	4,067
Postretirement benefits	70	70
AROs	753	694
Deferred investment tax credit	118	122
Deferred income taxes	3,201	3,053
Other non-current liabilities	336	349
Total non-current liabilities	21,179	20,065
Commitments and Contingencies (Notes 3 and 4)		
Equity		
<i>Common stockholder's equity</i>		
Common stock, authorized 125.0 shares; outstanding 84.1 shares in both periods	841	841
Other paid-in capital	9,094	8,174
Accumulated other comprehensive loss	(13)	(11)
Retained earnings	2,619	2,390
Total common stockholder's equity	12,541	11,394
Cumulative preferred stock, \$4.50 series, authorized 7.5 shares; outstanding 0.4 shares in both periods	37	37
Total equity	12,578	11,431
Total Liabilities and Equity	\$ 37,091	\$ 34,088

The accompanying notes are an integral part of these statements.

Consumers Energy Company

Consolidated Statements of Changes in Equity

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Total Equity at Beginning of Period	\$ 11,431	\$ 10,800	\$ 10,155
Common Stock			
At beginning and end of period	841	841	841
Other Paid-in Capital			
At beginning of period	8,174	7,759	7,284
Stockholder contribution	920	735	475
Return of stockholder contribution	—	(320)	—
At end of period	9,094	8,174	7,759
Accumulated Other Comprehensive Loss			
<i>Retirement benefits liability</i>			
At beginning of period	(11)	(15)	(15)
Net gain (loss) arising during the period	(2)	3	(1)
Amortization of net actuarial loss	—	1	1
At end of period	(13)	(11)	(15)
Retained Earnings			
At beginning of period	2,390	2,178	2,008
Net income	1,129	1,009	867
Dividends declared on common stock	(898)	(795)	(695)
Dividends declared on preferred stock	(2)	(2)	(2)
At end of period	2,619	2,390	2,178
Cumulative Preferred Stock			
At beginning and end of period	37	37	37
Total Equity at End of Period	\$ 12,578	\$ 11,431	\$ 10,800

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consumers Energy Company

Notes to the Consolidated Financial Statements

1: Significant Accounting Policies

Principles of Consolidation: CMS Energy and Consumers prepare their consolidated financial statements in conformity with GAAP. CMS Energy's consolidated financial statements comprise CMS Energy, Consumers, NorthStar Clean Energy, and all other entities in which CMS Energy has a controlling financial interest or is the primary beneficiary. Consumers' consolidated financial statements comprise Consumers and all other entities in which it has a controlling financial interest. CMS Energy uses the equity method of accounting for investments in companies and partnerships that are not consolidated, where they have significant influence over operations and financial policies but are not the primary beneficiary. CMS Energy and Consumers eliminate intercompany transactions and balances.

Use of Estimates: CMS Energy and Consumers are required to make estimates using assumptions that may affect reported amounts and disclosures. Actual results could differ from those estimates.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents: Cash and cash equivalents include short-term, highly liquid investments with original maturities of three months or less. Restricted cash and cash equivalents are held primarily for the repayment of securitization bonds and funds held in escrow. These amounts are classified as current assets since they relate to payments that could or will occur within one year.

Contingencies: CMS Energy and Consumers record estimated loss contingencies on their consolidated financial statements when it is probable that a loss has been incurred and when the amount of loss can be reasonably estimated. For environmental remediation projects in which the timing of estimated expenditures is considered reliably determinable, CMS Energy and Consumers record the liability at its net present value, using a discount rate equal to the interest rate on monetary assets that are essentially risk-free and have maturities comparable to that of the environmental liability. Unless regulatory accounting applies, CMS Energy and Consumers expense legal fees as incurred; fees incurred but not yet billed are accrued based on estimates of work performed.

Debt Issuance Costs, Discounts, Premiums, and Refinancing Costs: Upon the issuance of long-term debt, CMS Energy and Consumers defer issuance costs, discounts, and premiums and amortize those amounts over the terms of the associated debt. Debt issuance costs are presented as a direct deduction from the carrying amount of long-term debt on the balance sheet. Upon the refinancing of long-term debt, Consumers, as a regulated entity, defers any remaining unamortized issuance costs, discounts, and premiums associated with the refinanced debt and amortizes those amounts over the term of the newly issued debt. For the non-regulated portions of CMS Energy's business, any remaining unamortized issuance costs, discounts, and premiums associated with extinguished debt are charged to earnings.

Derivative Instruments: In order to support ongoing operations, CMS Energy and Consumers may enter into contracts for the future purchase and sale of various commodities, such as electricity, natural gas, and coal. These forward contracts are generally long-term in nature and result in physical delivery of the

commodity at a contracted price. Most of these contracts are not subject to derivative accounting for one or more of the following reasons:

- they do not have a notional amount (that is, a number of units specified in a derivative instrument, such as MWh of electricity or Bcf of natural gas)
- they qualify for the normal purchases and sales exception
- they cannot be net settled due in part to the absence of an active market for the commodity

Consumers also uses FTRs to manage price risk related to electricity transmission congestion. An FTR is a financial instrument that entitles its holder to receive compensation or requires its holder to remit payment for congestion-related transmission charges. Consumers accounts for FTRs as derivatives and changes in the fair value of FTRs are deferred as regulatory assets or liabilities. For details regarding CMS Energy's and Consumers' derivative instruments recorded at fair value, see Note 6, Fair Value Measurements.

Electricity Market Transactions: Wholesale electricity market operators require the submission of hourly day-ahead and real-time bids and offers for energy at locations across each region. CMS Energy and Consumers account for such transactions on a net hourly basis in each of the real-time and day-ahead markets, netted across all locations in the energy market. CMS Energy and Consumers record net hourly purchases in purchased and interchange power and net hourly sales in operating revenue on their consolidated statements of income. They record net billing adjustments upon receipt of settlement statements, record accruals for future net purchases and sales adjustments based on historical experience, and reconcile accruals to actual expenses and sales upon receipt of settlement statements.

EPS: CMS Energy calculates basic and diluted EPS using the weighted-average number of shares of common stock and dilutive potential common stock outstanding during the period. Potential common stock, for purposes of determining diluted EPS, includes the effects of nonvested stock awards, forward equity sales, and convertible securities. CMS Energy computes the effect on potential common stock using the treasury stock method. Potentially dilutive common shares issuable upon conversion of the convertible senior notes are determined using the if-converted method for calculating diluted EPS. Diluted EPS excludes the impact of antidilutive securities, which are those securities resulting in an increase in EPS or a decrease in loss per share. For EPS computations, see Note 14, Earnings Per Share—CMS Energy.

Impairment of Long-lived Assets and Equity Method Investments: CMS Energy and Consumers perform tests of impairment if certain triggering events occur that indicate the carrying amount of an asset may not be recoverable or that there has been a decline in value that may be other than temporary.

CMS Energy and Consumers evaluate long-lived assets held in use for impairment by calculating the undiscounted future cash flows expected to result from the use of the asset and its eventual disposition. If the undiscounted future cash flows are less than the carrying amount, CMS Energy and Consumers recognize an impairment loss equal to the amount by which the carrying amount exceeds the fair value. CMS Energy and Consumers estimate the fair value of the asset using quoted market prices, market prices of similar assets, or discounted future cash flow analyses.

CMS Energy also assesses equity method investments for impairment whenever there has been a decline in value that is other than temporary. This assessment requires CMS Energy to determine the fair value of the equity method investment. CMS Energy determines fair value using valuation methodologies, including discounted cash flows, and assesses the ability of the investee to sustain an earnings capacity that justifies the carrying amount of the investment. CMS Energy records an impairment if the fair value is less than the carrying amount and the decline in value is considered to be other than temporary.

Investment Tax Credits: CMS Energy and its subsidiaries use the flow-through method of accounting for investment tax credits. Under the flow-through method, the credit is recognized as a reduction to income tax expense when the related plant, property, and equipment is placed into service. For its regulated utility assets, Consumers amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

Inventory: CMS Energy and Consumers use the weighted-average cost method for valuing working gas, recoverable base gas in underground storage facilities, and materials and supplies inventory. CMS Energy and Consumers also use this method for valuing coal inventory, and they classify these amounts as generating plant fuel stock on their consolidated balance sheets.

CMS Energy and Consumers account for RECs and other environmental credits as inventory and use the weighted-average cost method to remove amounts from inventory. RECs and other environmental credits are used to satisfy compliance obligations related to the generation of power and in support of sustainability commitments. CMS Energy and Consumers classify these amounts within other assets on their consolidated balance sheets.

CMS Energy and Consumers evaluate inventory for impairment as required to ensure that its carrying value does not exceed the lower of cost or net realizable value.

Property Taxes: Property taxes are based on the taxable value of CMS Energy's and Consumers' real and personal property assessed by local taxing authorities. CMS Energy and Consumers record property tax expense over the fiscal year of the taxing authority for which the taxes are levied. The deferred property tax balance represents the amount of CMS Energy's and Consumers' accrued property tax that will be recognized over future governmental fiscal periods.

Other: For additional accounting policies, see:

- Note 3, Regulatory Matters
- Note 8, Plant, Property, and Equipment
- Note 9, Leases
- Note 10, Asset Retirement Obligations
- Note 11, Retirement Benefits
- Note 12, Stock-based Compensation
- Note 13, Income Taxes
- Note 14, Earnings Per Share—CMS Energy
- Note 15, Revenue
- Note 19, Variable Interest Entities

2: New Accounting Standards

Implementation of New Accounting Standards

ASU 2023-09, Incomes Taxes (Topic 740): Improvements to Income Tax Disclosures: This standard, which was effective on January 1, 2025 for CMS Energy and Consumers, requires expanded annual disclosures of the income taxes, including a more detailed reconciliation of the effective tax rate and disaggregated information on federal and state income taxes. The standard also requires disclosure of significant reconciling items and qualitative information about state and local jurisdictions contributing to income tax expense. The adoption of the new standard did not impact CMS Energy's or Consumers' liquidity, financial condition, or results of operations. The expanded disclosures required by this standard are included in Note 13, Income Taxes.

New Accounting Standards Not Yet Effective

ASU 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses: This standard requires public companies to provide disaggregated information about certain expense categories presented on the income statement. The guidance calls for annual and interim disclosures that separate specified components, such as employee compensation, depreciation, and amortization, within relevant expense line items in the notes to the financial statements. The standard is effective for annual reporting periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027, with early adoption permitted. CMS Energy and Consumers will adopt the guidance upon the effective date. The standard will not have an impact on CMS Energy’s or Consumers’ consolidated net income, cash flows, or financial position.

ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software: This standard updates guidance for capitalizing costs related to internal-use software development. The amendments remove references to the previous “project stage” model and clarify the threshold for when capitalization should begin, focusing on whether completion of the project is probable. The amendments are effective for annual and interim reporting periods beginning after December 15, 2027. The guidance may be applied on a prospective, retrospective, or modified transition basis. Early adoption is permitted. CMS Energy and Consumers are currently evaluating the new standard.

3: Regulatory Matters

Regulatory matters are critical to Consumers. The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers, such as Consumers’ rate cases and PSCR and GCR processes. Intervenors also participate in certain FERC matters, including FERC’s regulation of certain wholesale rates that affect Consumers’ power supply costs. These parties often challenge various aspects of those proceedings, including the prudence of Consumers’ policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC and FERC orders. Depending upon the specific issues, the outcomes of rate cases and proceedings, including judicial proceedings challenging MPSC and FERC orders or other actions, could negatively affect CMS Energy’s and Consumers’ liquidity, financial condition, and results of operations. Consumers cannot predict the outcome of these proceedings.

Regulatory Assets and Liabilities

Consumers is subject to the actions of the MPSC and FERC and therefore prepares its consolidated financial statements in accordance with the provisions of regulatory accounting. A utility must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, Consumers records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by non-regulated businesses.

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Presented in the following table are the regulatory assets and liabilities on Consumers' consolidated balance sheets:

	<i>In Millions</i>	
December 31	2025	2024
<i>Regulatory assets</i>		
<i>Current</i>		
Energy waste reduction plan incentive ¹	\$ 66	\$ 60
Retention incentive program ²	10	18
2022 PSCR underrecovery ³	—	126
Other	28	25
Total current regulatory assets	\$ 104	\$ 229
<i>Non-current</i>		
Costs of coal-fueled electric generating units to be retired ³	\$ 1,179	\$ 1,266
Postretirement benefits ²	589	747
Securitized costs ³	549	666
ARO ⁴	379	366
Decommissioning costs ²	197	158
Unamortized loss on reacquired debt ³	89	92
MGP sites ³	82	90
Energy waste reduction plan incentive ¹	64	64
Ludington overhaul contract dispute ²	60	31
Service restoration cost deferral ⁴	52	—
Energy waste reduction plan ³	26	31
Postretirement benefits expense deferral mechanism ²	22	21
Renewable Energy Plan ³	7	—
Retention incentive program ²	6	12
Other	54	25
Total non-current regulatory assets	\$ 3,355	\$ 3,569
Total regulatory assets	\$ 3,459	\$ 3,798
<i>Regulatory liabilities</i>		
<i>Current</i>		
Income taxes, net	\$ 47	\$ 53
ASP gain	28	47
Other	10	11
Total current regulatory liabilities	\$ 85	\$ 111
<i>Non-current</i>		
Cost of removal	\$ 2,727	\$ 2,665
Income taxes, net	1,118	1,163
Energy waste reduction plan	68	41
Green giving program	41	—
Postretirement benefits expense deferral mechanism	40	37
Renewable energy grant	38	40
ASP gain	19	46
Renewable Energy Plan	—	51
Other	40	24
Total non-current regulatory liabilities	\$ 4,091	\$ 4,067
Total regulatory liabilities	\$ 4,176	\$ 4,178

- ¹ These regulatory assets have arisen from an alternative-revenue program and are not associated with incurred costs or capital investments. Therefore, the MPSC has provided for recovery without a return.
- ² This regulatory asset is included in rate base, thereby providing a return.
- ³ The MPSC has provided a specific return on these regulatory assets.
- ⁴ These regulatory assets represent incurred costs for which the MPSC has provided recovery without a return on investment.

Regulatory Assets

Energy Waste Reduction Plan Incentive: The energy waste reduction incentive mechanism provides a financial incentive if the energy savings of Consumers' customers exceed annual targets established by the MPSC. Consumers accounts for this program as an alternative-revenue program that meets the criteria for recognizing revenue related to the incentive as soon as energy savings exceed the annual targets established by the MPSC.

In January 2026, the MPSC approved a settlement agreement authorizing Consumers to collect \$64 million during 2026 as an incentive for exceeding its statutory savings targets in 2024. Consumers recognized incentive revenue under this program of \$64 million in 2024.

Consumers also exceeded its statutory savings targets in 2025, achieved certain other goals, and will request the MPSC's approval to collect \$64 million in the energy waste reduction reconciliation to be filed in May 2026. Consumers recognized incentive revenue under this program of \$64 million in 2025.

Retention Incentive Program: To ensure necessary staffing at the D.E. Karn and J.H. Campbell coal-fueled generating units through their retirement, Consumers established retention incentive programs. The MPSC has approved deferred accounting treatment for the retention and severance costs incurred under these programs and has allowed for recovery over three years. These MPSC-approved retention plans concluded in November 2025. For additional details regarding retention incentive programs, see Note 20, Exit Activities and Asset Sales.

2022 PSCR Underrecovery: As a result of rising fuel prices during 2022, Consumers' power supply costs for 2022 were significantly higher than those projected in its 2022 PSCR plan. At the end of 2022, Consumers had recorded \$401 million of under-recovered power supply costs. In 2023, the MPSC authorized Consumers to recover the 2022 underrecovery amount over three years, providing immediate relief to electric customers.

Costs of Coal-fueled Electric Generating Units to be Retired: In 2022, the MPSC approved Consumers' plans to retire the J.H. Campbell coal-fueled generating units in 2025. The MPSC authorized regulatory asset treatment for Consumers to recover the remaining book value of the units upon their retirement, as well as a 9.0-percent return on equity, through 2040, the units' original retirement date. Accordingly, in 2022, Consumers removed from total plant, property, and equipment an amount of \$1.3 billion, representing the projected remaining book value of the electric generating units upon their retirement, and recorded it as a non-current regulatory asset on its consolidated balance sheets.

As discussed further below, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Such orders authorize Consumers to obtain cost recovery at FERC; thus, Consumers has deferred the costs of complying with these orders as a regulatory asset.

Postretirement Benefits: As part of the ratemaking process, the MPSC allows Consumers to recover the costs of postretirement benefits. Accordingly, Consumers defers the net impact of actuarial losses and gains, prior service costs and credits, and settlements associated with postretirement benefits as a regulatory asset or liability. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. For details about the amortization periods, see Note 11, Retirement Benefits.

Securitized Costs: The MPSC has issued securitization financing orders authorizing Consumers to issue securitization bonds in order to finance the recovery of the remaining book value of three smaller natural gas-fueled electric generating units that Consumers retired in 2015, seven smaller coal-fueled electric generating units that Consumers retired in 2016, and the D.E. Karn coal-fueled electric generating units that Consumers retired in 2023. Consumers has removed from plant, property, and equipment and recorded as a regulatory asset the book value of these units. Consumers is amortizing the regulatory asset over the life of the related securitization bonds, which it issued through subsidiaries in 2014 and 2023. For additional details regarding the securitization bonds, see Note 5, Financings and Capitalization—Securitization Bonds.

ARO: The recovery of the underlying asset investments and related removal and monitoring costs of recorded AROs is approved by the MPSC in depreciation rate cases. Consumers records a regulatory asset and a regulatory liability for timing differences between the recognition of AROs for financial reporting purposes and the recovery of these costs from customers. The recovery period approximates the useful life of the assets to be removed.

Decommissioning Costs: In Consumers' electric depreciation and general rate cases, the MPSC has authorized Consumers to remove from depreciation rates the costs of decommissioning the D.E. Karn coal-fueled electric generating units, and instead defer those costs as a regulatory asset to be recovered through 2031. Additionally, ash disposal costs related to Consumers' retired coal-fueled generating units may be deferred as a regulatory asset and collected over a ten-year period. In its 2022 order approving Consumers' integrated resource plan, the MPSC authorized similar treatment for the decommissioning and ash disposal costs associated with the J.H. Campbell coal-fueled generating units that were planned for retirement in 2025.

Unamortized Loss on Reacquired Debt: Under regulatory accounting, any unamortized discount, premium, or expense related to debt redeemed with the proceeds of new debt is deferred and amortized over the life of the new debt.

MGP Sites: Consumers is incurring environmental remediation and other response activity costs at 23 former MGP facilities. The MPSC allows Consumers to recover from its natural gas customers over a ten-year period the costs incurred to remediate the MGP sites. For additional information, see Note 4, Contingencies and Commitments—Consumers Gas Utility Contingencies.

Ludington Overhaul Contract Dispute: The MPSC has authorized Consumers to defer as a regulatory asset costs associated with correcting incomplete, nonconforming, and defective work performed by TAES during a major overhaul and upgrade of Ludington. Consumers will defer such costs while post-verdict proceedings and any appeals in the litigation with TAES and Toshiba continue; such costs will be offset, in part or in whole, by future litigation proceeds received from TAES or Toshiba. Consumers has also deferred replacement power costs due to outages resulting from correcting this work. Consumers will have the opportunity to seek appropriate recovery and ratemaking treatment for amounts recorded as a regulatory asset following resolution of the litigation. During 2025, cash expenditures associated with the Ludington overhaul contract dispute were \$30 million. For additional details on the contract dispute, see Note 4, Contingencies and Commitments—Consumers Electric Utility Contingencies.

Service Restoration Cost Deferral: As a result of catastrophic storms in Consumers' electric service territory, Consumers incurred significant service restoration costs during March and April 2025. In April 2025, Consumers filed with the MPSC an ex parte application requesting approval to defer, as a regulatory asset, operating and maintenance expenses associated with the storms. In June 2025, the MPSC approved the application, authorizing the deferral of these expenses for accounting purposes. Recovery of this regulatory asset will be requested in a future case.

Energy Waste Reduction Plan: Michigan law requires electric and gas utilities to implement programs that reduce energy consumption through energy efficiency and demand-side energy conservation. Utilities may recover the cost of achieving specified reductions in customers' electricity and gas use through surcharges. The amount of spending incurred in excess of surcharges collected is recorded as a regulatory asset and amortized as surcharges are collected from customers over the plan period. The amount of surcharges collected in excess of spending incurred is recorded as a regulatory liability and amortized as costs are incurred.

Postretirement Benefits Expense Deferral Mechanism: In Consumers' general rate cases, the MPSC approved a mechanism allowing Consumers to defer for future recovery or refund pension and OPEB expenses above or below the amounts used to set existing rates. Amounts deferred will be collected from or refunded to customers over ten years.

Renewable Energy Plan: Under Michigan law, renewable energy standards specify how much electricity must come from renewable sources and which technologies, such as wind, solar, and certain biomass, qualify. Utilities may recover compliance costs, including renewable power purchases (and related financial mechanisms), depreciation, property taxes, interest, and other operating and maintenance expenses for company-owned renewable assets, along with a return on those assets. The MPSC allows Consumers to transfer and collect a portion of these costs through its PSCR process. Incremental costs may be collected through surcharges. If spending exceeds amounts collected, the difference is recorded as a regulatory asset and amortized as recovered from customers; this excludes amounts related to return on equity. If collections exceed spending, the excess is recorded as a regulatory liability and amortized as future costs are incurred for operating renewable facilities and purchasing RECs under renewable energy agreements.

Regulatory Liabilities

Income Taxes, Net: Consumers records regulatory assets and liabilities to reflect the difference between deferred income taxes recognized for financial reporting purposes and amounts previously reflected in Consumers' rates. This net balance will decrease over the remaining life of the related temporary differences and flow through income tax expense. The majority of the net regulatory liability recorded related to income taxes is associated with plant assets that are subject to normalization, which is governed by the Internal Revenue Code, and will be returned to customers over the remaining book life of the related plant assets. For additional details on deferred income taxes, see Note 13, Income Taxes.

ASP Gain: In April 2024, Consumers sold its unregulated ASP business to a non-affiliated company, resulting in a \$110 million gain. In July 2024, the MPSC approved the utilization of \$27.5 million, or one-fourth, of the gain on the sale as an offset to the revenue deficiency in lieu of additional rate relief during the 12-month period beginning October 1, 2024, with the remaining three-fourths of the gain, or \$82.5 million, to be credited to customers as a bill credit over a three-year period beginning October 1, 2024.

Cost of Removal: The MPSC allows Consumers to collect amounts from customers to fund future asset removal activities. This regulatory liability is reduced as costs are incurred to remove the assets at the end of their useful lives.

Green Giving Program: In conjunction with Consumers' voluntary green pricing program, the MPSC has directed Consumers to use surplus program funds to support renewable-energy participation by low-income customers.

Renewable Energy Grant: In 2013, Consumers received a \$69 million renewable energy grant for Lake Winds® Energy Park, which began operations in 2012. This grant reduces Consumers' cost of complying with Michigan's renewable portfolio standard and, accordingly, reduces the overall renewable energy surcharge to be collected from customers. The regulatory liability recorded for the grant will be amortized over the life of Lake Winds® Energy Park. Consumers presents the amortization as a reduction to maintenance and other operating expenses on its consolidated statements of income.

Consumers Electric Utility

2024 Electric Rate Case: In May 2024, Consumers filed an application with the MPSC seeking a rate increase of \$325 million, made up of two components. First, Consumers requested a \$303 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending February 28, 2026. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability and cleaner energy resources. Second, Consumers requested approval of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rates authorized in accordance with previous electric rate orders.

In October 2024, Consumers revised its requested increase to \$277 million, primarily to reflect the removal of projected capital investments associated with certain solar facilities that Consumers incorporated into its amended Renewable Energy Plan.

In March 2025, the MPSC issued an order authorizing an annual rate increase of \$176 million, which is inclusive of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025.

J.H. Campbell Emergency Order: In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. Subsequently, the U.S. Secretary of Energy issued two additional emergency orders for 90 days each, ultimately requiring continued operation of J.H. Campbell through February 17, 2026. These orders stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and DOE regulations, the orders authorize Consumers to obtain cost recovery at FERC.

As directed, Consumers has continued to make J.H. Campbell available in the MISO market and, in June 2025, filed a complaint at FERC seeking a modification of the MISO Tariff that would enable Consumers to recover the costs of complying with the emergency orders. Consumers' complaint sought a mechanism in the MISO Tariff that would allow allocation of those compliance costs across the MISO North and Central regions, consistent with the nature of the energy emergency declared in the U.S. Secretary of Energy orders. In August 2025, FERC granted Consumers' complaint and ordered MISO to revise its tariff accordingly. MISO submitted a compliance filing with FERC in September 2025, and FERC approval of the compliance filing remains pending.

In January 2026, Consumers filed a request at FERC seeking recovery of the net financial impact of complying with the May 2025 emergency order, which was \$42 million after applying MISO revenues of \$78 million. This filing encompasses recovery sought by the joint owners of J.H. Campbell.

For the second emergency order period through December 31, 2025, the net financial impact of compliance was \$93 million after applying MISO revenues of \$77 million. Consumers will seek recovery of these compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order. The ultimate financial impact remains subject to the outcome of the FERC proceeding and any future guidance or interpretation.

Consumers Gas Utility

2024 Gas Rate Case: In December 2024, Consumers filed an application with the MPSC seeking an annual rate increase of \$248 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2026. In July 2025, Consumers revised its requested increase to \$217 million. In September 2025, the MPSC issued an order authorizing an annual rate increase of \$157.5 million, based on a 9.80-percent authorized return on equity. The new rates became effective in November 2025.

PSCR and GCR

The PSCR and GCR ratemaking processes are designed to allow Consumers to recover all of its power supply and purchased natural gas costs if incurred under reasonable and prudent policies and practices. The MPSC reviews these costs, policies, and practices in annual plan and reconciliation proceedings. Consumers adjusts its PSCR and GCR billing charges monthly, subject to ceiling factor limitations, in order to minimize the underrecovery or overrecovery amount in the annual reconciliations. Underrecoveries represent power supply and purchased natural gas costs that will be recovered from customers; overrecoveries represent previously collected revenues that will be refunded to customers.

Presented in the following table are the liabilities for PSCR and GCR underrecoveries and overrecoveries reflected on Consumers' consolidated balance sheets:

December 31	<i>In Millions</i>	
	2025	2024
<i>Assets</i>		
PSCR underrecoveries	\$ 38	\$ —
Accounts receivable and accrued revenue	\$ 38	\$ —
<i>Liabilities</i>		
PSCR overrecoveries	\$ —	\$ 13
GCR overrecoveries	28	25
Accrued rate refunds	\$ 28	\$ 38

4: Contingencies and Commitments

CMS Energy and Consumers are involved in various matters that give rise to contingent liabilities. Depending on the specific issues, the resolution of these contingencies could negatively affect CMS Energy’s and Consumers’ liquidity, financial condition, and results of operations. In their disclosures of these matters, CMS Energy and Consumers provide an estimate of the possible loss or range of loss when such an estimate can be made. Disclosures stating that CMS Energy or Consumers cannot predict the outcome of a matter indicate that they are unable to estimate a possible loss or range of loss for the matter.

CMS Energy Contingencies

CMS Land retained environmental remediation obligations for the collection and treatment of leachate at Bay Harbor after selling its interests in the development in 2002. Leachate is produced when water enters into cement kiln dust piles left over from former cement plant operations at the site. In 2012, CMS Land and EGLE finalized an agreement establishing the final remedies and the future water quality criteria at the site. CMS Land completed all construction necessary to implement the remedies required by the agreement and will continue to maintain and operate a system to discharge treated leachate into Little Traverse Bay under an NPDES permit, which was valid through 2025. CMS Land submitted a renewal request in March 2025, and will continue to operate under the existing permit until a renewal is issued.

At December 31, 2025, CMS Energy had a recorded liability of \$48 million for its remaining obligations for environmental remediation. CMS Energy calculated this liability based on discounted projected costs, using a discount rate of 4.34 percent and an inflation rate of 1 percent on annual operating and maintenance costs. The undiscounted amount of the remaining obligation is \$62 million. CMS Energy expects to pay the following amounts for long-term leachate disposal and operating and maintenance costs in each of the next five years:

	<i>In Millions</i>				
	2026	2027	2028	2029	2030
Long-term leachate disposal and operating and maintenance costs	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4

CMS Energy’s estimate of response activity costs and the timing of expenditures could change if there are changes in circumstances or assumptions used in calculating the liability. Although a liability for its present estimate of remaining response activity costs has been recorded, CMS Energy cannot predict the ultimate financial impact or outcome of this matter.

Consumers Electric Utility Contingencies

Electric Environmental Matters: Consumers’ operations are subject to environmental laws and regulations. Historically, Consumers has generally been able to recover, in customer rates, the costs to operate its facilities in compliance with these laws and regulations.

Cleanup and Solid Waste: Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. Consumers believes that these costs should be recoverable in rates, but cannot guarantee that outcome. Consumers estimates its liability for NREPA sites for which it can estimate a range of loss to be between \$2 million and \$3 million. At December 31, 2025, Consumers had a recorded liability of \$2 million, the minimum amount in the range of its estimated probable NREPA liability, as no amount in the range was considered a better estimate than any other amount.

Consumers is a potentially responsible party at a number of contaminated sites administered under CERCLA. CERCLA liability is joint and several. In 2010, Consumers received official notification from the EPA that identified Consumers as a potentially responsible party for cleanup of PCBs at the Kalamazoo River CERCLA site. The notification claimed that the EPA had reason to believe that Consumers disposed of PCBs and arranged for the disposal and treatment of PCB-containing materials at portions of the site. In 2011, Consumers received a follow-up letter from the EPA requesting that Consumers agree to participate in a removal action plan along with several other companies for an area of lower Portage Creek, which is connected to the Kalamazoo River. All parties asked to participate in the removal action plan, including Consumers, declined to accept liability. Until further information is received from the EPA, Consumers is unable to estimate a range of potential liability for cleanup of the river.

Based on its experience, Consumers estimates its share of the total liability for known CERCLA sites to be between \$3 million and \$8 million. Various factors, including the number and creditworthiness of potentially responsible parties involved with each site, affect Consumers' share of the total liability. At December 31, 2025, Consumers had a recorded liability of \$3 million for its share of the total liability at these sites, the minimum amount in the range of its estimated probable CERCLA liability, as no amount in the range was considered a better estimate than any other amount.

The timing of payments related to Consumers' remediation and other response activities at its CERCLA and NREPA sites is uncertain. Consumers periodically reviews these cost estimates. A change in the underlying assumptions, such as an increase in the number of sites, different remediation techniques, the nature and extent of contamination, and legal and regulatory requirements, could affect its estimates of NREPA and CERCLA liability.

Ludington Overhaul Contract Dispute: Consumers and DTE Electric, co-owners of Ludington, entered into a 2010 engineering, procurement, and construction agreement with Toshiba International, under which Toshiba International contracted to perform a major overhaul and upgrade of Ludington. Toshiba International later assigned the contract and all of its obligations to TAES. TAES' work under the contract was incomplete, defective, and non-conforming. Consumers and DTE Electric repeatedly documented TAES' failure to perform under the contract and demanded that TAES provide a comprehensive plan to resolve those matters, including adherence to its warranty commitments and other contractual obligations. Consumers and DTE Electric engaged in extensive efforts to resolve these issues with TAES, including a formal demand to TAES' parent, Toshiba, under a parent guaranty it provided. TAES did not provide a comprehensive plan or otherwise meet its performance obligations. As a result of TAES' defaults, Consumers and DTE Electric terminated the contract.

In order to enforce their rights under the contract and parent guaranty, and to pursue appropriate damages, Consumers and DTE Electric filed a complaint against TAES and Toshiba in the U.S. District Court for the Eastern District of Michigan in 2022. TAES and Toshiba filed a motion to dismiss the complaint, along with an answer and counterclaims seeking approximately \$15 million in damages related to payments allegedly owed under the parties' contract. The court denied the motion to dismiss filed by TAES and Toshiba.

The case against TAES went to trial before a jury and, in December 2025, the jury rendered a verdict in Consumers' and DTE Electric's favor. The jury found that TAES breached the parties' contract and awarded damages of \$383 million. The parties separately stipulated to \$11 million in additional liquidated damages for late performance by TAES. These amounts are subject to pre- and post-judgment interest. In addition, the jury rejected TAES' counterclaim, determining that Consumers and DTE Electric did not breach the contract. The parent guaranty provided by Toshiba allows Consumers and DTE Electric to recover legal costs in addition to damages. The parties are still engaged in post-verdict proceedings at the District Court and the jury verdict may be appealed; these processes could take two years or more to

conclude with finality. The jury verdict was a favorable outcome for Consumers but an unfavorable outcome in these additional proceedings could have a material adverse effect on CMS Energy's and Consumers' financial condition, results of operations, or liquidity. Consumers and DTE Electric must still also resolve their claim against Toshiba under the parent guaranty, which is still pending but which was bifurcated by the Court from the claims against TAES.

Previously, Toshiba announced that TBJH became the majority shareholder and new parent company of Toshiba through a common stock purchase. TBJH is a subsidiary of a Japanese private equity firm. Consumers and DTE Electric do not believe that this affects their rights under the parent guaranty provided by Toshiba.

With MPSC approval, Consumers and DTE Electric were authorized to defer as a regulatory asset the costs associated with repairing or replacing the defective work performed by TAES while the litigation with TAES and Toshiba remains pending. Consumers currently estimates that its share of repair, replacement, and other damages resulting from TAES' defective work is approximately \$350 million, which is expected to be offset in part or entirely by future litigation proceeds received from TAES or Toshiba. Consumers and DTE Electric will have the opportunity to seek appropriate recovery and ratemaking treatment for amounts recorded as a regulatory asset following resolution of the litigation, including any amounts not recovered from TAES or Toshiba. Consumers cannot predict the financial impact or outcome of such proceedings.

Consumers Gas Utility Contingencies

Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. These sites include 23 former MGP facilities. Consumers operated the facilities on these sites for some part of their operating lives. For some of these sites, Consumers has no present ownership interest or may own only a portion of the original site.

At December 31, 2025, Consumers had a recorded liability of \$59 million for its remaining obligations for these sites. Consumers expects to pay the following amounts for remediation and other response activity costs in each of the next five years:

	<i>In Millions</i>				
	2026	2027	2028	2029	2030
Remediation and other response activity costs	\$ 3	\$ 8	\$ 25	\$ 11	\$ 3

Consumers periodically reviews these cost estimates. Any significant change in the underlying assumptions, such as an increase in the number of sites, changes in remediation techniques, or legal and regulatory requirements, could affect Consumers' estimates of annual response activity costs and the MGP liability.

Pursuant to orders issued by the MPSC, Consumers defers its MGP-related remediation costs and recovers them from its customers over a ten-year period. At December 31, 2025, Consumers had a regulatory asset of \$82 million related to the MGP sites.

Guarantees

Presented in the following table are CMS Energy's and Consumers' guarantees at December 31, 2025:

<i>In Millions</i>				
Guarantee Description	Issue Date	Expiration Date	Maximum Obligation	Carrying Amount
CMS Energy, including Consumers				
Indemnity obligations from sale of membership interests in VIEs ¹	various	various	\$ 230	\$ —
Indemnity obligations from stock and asset sale agreements ²	various	indefinite	152	—
Guarantee ³	2011	indefinite	30	—
Consumers				
Guarantee ³	2011	indefinite	\$ 30	\$ —

- ¹ These obligations arose from the sale of membership interests in Aviator Wind, BG Solar Holdings, Newport Solar Holdings, and NWO Holdco to tax equity investors. NorthStar Clean Energy provided certain indemnity obligations that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. These obligations are generally capped at an amount equal to the tax equity investor's capital contributions plus a specified return, less any distributions and tax benefits it receives, in connection with its membership interest. For any indemnity obligations related to Aviator Wind, NorthStar Clean Energy would recover 49 percent of any amounts paid to the tax equity investor from the other owner of Aviator Wind Equity Holdings. Additionally, Aviator Wind holds insurance coverage that would partially protect against losses incurred as a result of certain failures to qualify for production tax credits. For further details on NorthStar Clean Energy's ownership interest in these entities, see Note 19, Variable Interest Entities.
- ² These obligations arose from stock and asset sale agreements under which CMS Energy or a subsidiary of CMS Energy indemnified the purchaser for losses resulting from various matters, including claims related to taxes. The maximum obligation amount is mostly related to an Equatorial Guinea tax claim.
- ³ This obligation comprises a guarantee provided by Consumers to the DOE in connection with a settlement agreement regarding damages resulting from the department's failure to accept spent nuclear fuel from nuclear power plants formerly owned by Consumers.

Additionally, in the normal course of business, CMS Energy, Consumers, and certain other subsidiaries of CMS Energy have entered into various agreements containing tax and other indemnity provisions for which they are unable to estimate the maximum potential obligation. CMS Energy and Consumers consider the likelihood that they would be required to perform or incur substantial losses related to these indemnities and those disclosed in the table to be remote.

Other Contingencies

In addition to the matters disclosed in this Note and Note 3, Regulatory Matters, there are certain other lawsuits and administrative proceedings before various courts and governmental agencies, as well as unasserted claims that may result in such proceedings, arising in the ordinary course of business to which CMS Energy, Consumers, and certain other subsidiaries of CMS Energy are parties. These other lawsuits, proceedings, and unasserted claims may involve personal injury, property damage, contracts, environmental matters, federal and state taxes, rates, licensing, employment, and other matters. Certain of these matters, while potentially substantial, are covered by insurance and the insurer or insurers are involved in the relevant proceedings. Further, CMS Energy and Consumers occasionally self-report

certain regulatory non-compliance matters that may or may not eventually result in administrative proceedings. CMS Energy and Consumers believe that the outcome of any one of these proceedings and potential claims will not have a material negative effect on their consolidated results of operations, financial condition, or liquidity.

Contractual Commitments

Purchase Obligations: Purchase obligations arise from long-term contracts for the purchase of commodities and related services, primarily long-term PPAs, and construction and service agreements. Related-party PPAs are between Consumers and certain affiliates of NorthStar Clean Energy. Presented in the following table are CMS Energy's and Consumers' contractual purchase obligations at December 31, 2025 for each of the periods shown:

	<i>In Millions</i>						
	Payments Due						
	Total	2026	2027	2028	2029	2030	Beyond 2030
CMS Energy, including Consumers							
Total PPAs	\$16,983	\$ 873	\$ 904	\$ 930	\$ 942	\$ 1,011	\$ 12,323
Other	3,582	1,511	762	468	391	303	147
Total purchase obligations	20,565	2,384	1,666	1,398	1,333	1,314	12,470
Consumers							
<i>PPAs</i>							
MCV PPA	\$ 5,539	\$ 339	\$ 312	\$ 316	\$ 308	\$ 395	\$ 3,869
Related-party PPAs	62	32	30	—	—	—	—
Other PPAs	11,382	502	562	614	634	616	8,454
Total PPAs	\$16,983	\$ 873	\$ 904	\$ 930	\$ 942	\$ 1,011	\$ 12,323
Other	2,700	1,185	599	363	266	232	55
Total purchase obligations	19,683	2,058	1,503	1,293	1,208	1,243	12,378

MCV PPA: Consumers has a PPA with the MCV Partnership giving Consumers the right to purchase up to 1,240 MW of capacity and energy produced by the MCV Facility through May 2030. The MCV PPA provides for:

- a capacity charge of \$10.14 per MWh of available capacity through March 2025 and \$5.00 per MWh of available capacity from March 2025 through the termination date of the PPA
- a fixed energy charge of \$6.30 per MWh for on-peak hours and \$6.00 for off-peak hours
- a variable energy charge based on the MCV Partnership's cost of production for energy delivered to Consumers
- a \$5 million annual contribution by the MCV Partnership to a renewable resources program through March 2025

Capacity and energy charges under the MCV PPA were \$360 million in 2025, \$358 million in 2024, and \$340 million in 2023.

In September 2025, Consumers entered into a new ten-year PPA with the MCV Partnership for the purchase of up to 1,240 MW of capacity and associated energy from the MCV Facility, effective June 1, 2030. Under the terms of the new agreement, Consumers will pay a monthly capacity charge of \$5.00 per MWh of available capacity. Energy payments include a fixed component designed to recover non-fuel operating costs and a variable component based on the MCV Partnership's cost of production for

energy delivered to Consumers. The agreement, which is subject to MPSC approval, supports Consumers' ongoing resource adequacy and energy supply planning efforts.

Other PPAs: Consumers has PPAs expiring through 2060 with various counterparties. The majority of the PPAs have capacity and energy charges for delivered energy. Capacity and energy charges under these PPAs were \$603 million in 2025, \$565 million in 2024, and \$498 million in 2023. In addition, CMS Energy and Consumers account for several of their PPAs as leases. See Note 9, Leases for more information about CMS Energy's and Consumers' lease obligations.

5: Financings and Capitalization

Presented in the following table is CMS Energy's long-term debt at December 31:

<i>In Millions, Except Interest Rate and Maturity</i>				
	Interest Rate (%)	Maturity	2025	2024
CMS Energy, including Consumers				
<i>CMS Energy, parent only</i>				
<i>Senior notes</i>	3.600	2025	\$ —	\$ 250
	3.000	2026	300	300
	2.950	2027	275	275
	3.450	2027	350	350
	4.700	2043	250	250
	4.875	2044	300	300
			\$ 1,475	\$ 1,725
<i>Convertible senior notes¹</i>	3.375 ²	2028	\$ 800	\$ 800
	3.125 ³	2031	1,000	—
			\$ 1,800	\$ 800
<i>Junior subordinated notes⁴</i>	4.750 ⁵	2050	\$ 500	\$ 500
	3.750 ⁶	2050	400	400
	6.500 ⁷	2055	1,000	—
	5.625	2078	200	200
	5.875	2078	280	280
	5.875	2079	630	630
			\$ 3,010	\$ 2,010
<i>Term loan facilities</i>	variable	2025	\$ —	\$ 90
	variable	2025	—	400
			\$ —	\$ 490
Total CMS Energy, parent only			\$ 6,285	\$ 5,025
<i>CMS Energy subsidiaries</i>				
<i>Consumers</i>			\$ 12,196	\$ 11,370
<i>NorthStar Clean Energy</i>				
Revolving credit facility	variable ⁸	2028	235	150
Construction financing agreement ⁹	variable	Five years after conversion date	223	—
Total principal amount outstanding			\$ 18,939	\$ 16,545
Current amounts			(950)	(1,192)
Unamortized discounts			(28)	(29)
Unamortized issuance costs			(154)	(130)
Total CMS Energy long-term debt			\$ 17,807	\$ 15,194

¹ Holders of the convertible senior notes may convert their notes at their option in accordance with the conditions outlined in the related indentures. CMS Energy will settle conversions of the notes in accordance with the terms outlined in the related indentures. The conversion rate will be subject to adjustment for

anti-dilutive events and fundamental change and redemption provisions as described in the related indentures. There are no sinking fund requirements for the notes.

- ² At December 31, 2025, the conversion price for the notes was \$73.61 per share of common stock. Unamortized debt costs associated with this issuance were \$6 million at December 31, 2025 and \$9 million at December 31, 2024.
- ³ At December 31, 2025, the conversion price for the notes was \$90.61 per share of common stock. Unamortized debt costs associated with this issuance were \$12 million at December 31, 2025.
- ⁴ These unsecured obligations rank subordinate and junior in right of payment to all of CMS Energy's existing and future senior indebtedness.
- ⁵ On June 1, 2030, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 4.116 percent.
- ⁶ On December 1, 2030, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 2.900 percent.
- ⁷ On June 1, 2035, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 1.961 percent.
- ⁸ Loans under this facility have an interest rate of one-month Term SOFR plus 1.750 percent less an adjustment of 0.050 percent for green credit advances. At December 31, 2025, the weighted-average interest rate for the loans issued under this facility was 5.436 percent.
- ⁹ Loans under this facility have an interest rate of one-month Term SOFR plus 2.250 percent. At December 31, 2025, the weighted-average interest rate for the loans issued under this facility was 6.476 percent. At completion of project construction, scheduled for the first half of 2026, a portion of this financing will convert into a term loan that will mature five years after the conversion date.

Presented in the following table is Consumers' long-term debt at December 31:

In Millions, Except Interest Rate and Maturity

	Interest Rate (%)	Maturity	2025	2024
Consumers				
<i>First mortgage bonds</i>	5.240	2026	\$ 115	\$ 115
	3.680	2027	100	100
	3.390	2027	35	35
	4.650	2028	425	425
	3.800	2028	300	300
	4.900	2029	500	500
	5.070	2029	50	50
	4.600	2029	600	600
	4.700	2030	700	700
	4.500	2031	500	—
	5.170	2032	95	95
	3.600	2032	350	350
	3.180	2032	100	100
	4.625	2033	700	700
	5.050	2035	625	—
	5.800	2035	175	175
	5.380	2037	140	140
	3.520	2037	335	335
	4.010	2038	215	215
	6.170	2040	50	50
	4.970	2040	50	50
	4.310	2042	263	263
	3.950	2043	425	425
	4.100	2045	250	250
	3.250	2046	450	450
	3.950	2047	350	350
	4.050	2048	550	550
	4.350	2049	550	550
	3.750	2050	300	300
	3.100	2050	550	550
	3.500	2051	575	575
	2.650	2052	300	300
	4.200	2052	450	450
	3.860	2052	50	50
	4.280	2057	185	185
	2.500	2060	525	525
	4.350	2064	250	250
	variable ¹	2069	76	76
	variable ¹	2070	134	134
	variable ¹	2070	127	127
			\$ 12,520	\$ 11,395

In Millions, Except Interest Rate and Maturity

	Interest Rate (%)	Maturity	2025	2024
<i>Tax-exempt revenue bonds</i>	0.875 ²	2035	\$ 35	\$ 35
	3.350 ³	2049	75	75
			\$ 110	\$ 110
2014 Securitization bonds	3.528 ⁴	2029 ⁵	\$ 81	\$ 112
2023 Securitization bonds	5.281 ⁶	2028-2031 ⁵	504	588
			\$ 585	\$ 700
Total principal amount outstanding			\$ 13,215	\$ 12,205
Current amounts			(573)	(452)
Long-term debt – related parties ⁷ principal amount outstanding		2043-2060	(1,019)	(835)
Unamortized discounts			(26)	(27)
Unamortized issuance costs			(73)	(73)
Total long-term debt			\$ 11,524	\$ 10,818

¹ The variable-rate bonds bear interest quarterly at a rate of three-month SOFR minus 0.038 percent, subject to a zero-percent floor. At December 31, 2025, the interest rates were 3.685 percent for bonds due September 2069, 3.851 percent for bonds due May 2070, and 3.897 percent for bonds due October 2070. The interest rate for the variable-rate bonds at December 31, 2024 were 4.320 percent, 4.483 percent, and 4.551 percent, respectively. The holders of these variable-rate bonds may put them to Consumers for redemption on certain dates prior to their stated maturity, including dates within one year of December 31, 2025.

² The interest rate on these tax-exempt revenue bonds will reset on October 8, 2026.

³ The interest rate on these tax-exempt revenue bonds will reset on October 1, 2027.

⁴ The weighted-average interest rate for Consumers' securitization bonds issued through its subsidiary, Consumers 2014 Securitization Funding, was 3.528 percent at December 31, 2025 and 2024.

⁵ Principal and interest payments are made semiannually.

⁶ The weighted-average interest rate for Consumers' securitization bonds issued through its subsidiary, Consumers 2023 Securitization Funding, was 5.281 percent at December 31, 2025 and 5.322 percent at December 31, 2024.

⁷ Long-term debt – related parties reflects Consumers' outstanding debt held by its parent as a result of CMS Energy's repurchase of Consumers' first mortgage bonds. Unamortized discounts associated with the repurchase of Consumers' first mortgage bonds were \$5 million at December 31, 2025 and 2024. Unamortized issuance costs were \$9 million at December 31, 2025 and \$7 million at December 31, 2024.

Financings: Presented in the following table is a summary of major long-term debt issuances during 2025:

	Principal (In Millions)	Interest Rate (%)	Issuance Date	Maturity Date
CMS Energy, parent only				
Junior subordinated notes	\$ 1,000	6.500	February 2025	June 2055
Term loan credit agreement	110	variable	February 2025	December 2025
Convertible senior notes	1,000	3.125	November 2025	May 2031
Total CMS Energy, parent only	\$ 2,110			
NorthStar Clean Energy				
Construction financing agreement	\$ 223	variable	February 2025	Five years after conversion date
Total NorthStar Clean Energy	\$ 223			
Consumers				
First mortgage bonds	\$ 500	4.500	May 2025	January 2031
First mortgage bonds	625	5.050	May 2025	May 2035
Total Consumers	\$ 1,125			
Total CMS Energy	\$ 3,458			

Retirements: Presented in the following table is a summary of major long-term debt retirements during 2025:

	Principal (In Millions)	Interest Rate (%)	Retirement Date	Maturity Date
CMS Energy, parent only				
Term loan credit agreement	\$ 400	variable	February 2025	September 2025
Term loan credit agreement	200	variable	February 2025	December 2025
Senior notes	250	3.600	November 2025	November 2025
Total CMS Energy, parent only	\$ 850			
Total CMS Energy	\$ 850			

CMS Energy's Purchase of Consumers' First Mortgage Bonds: CMS Energy purchased Consumers' first mortgage bonds with a principal balance of \$184 million during 2025 in exchange for cash of \$109 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds was accounted for as a debt extinguishment and resulted in a pre-tax gain of \$72 million during 2025, which was recorded in other income on CMS Energy's consolidated statements of income. Interest expense related to the repurchased bonds was \$28 million for the year ended December 31, 2025, which was recorded in interest expense – related parties on Consumers' consolidated statements of income.

In 2024, CMS Energy purchased Consumers' first mortgage bonds with a principal balance of \$404 million in exchange for cash of \$289 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds resulted in a pre-tax gain of \$110 million for the year ended December 31, 2024. Interest expense related to the repurchased bonds was \$19 million for the year ended December 31, 2024.

In 2023, CMS Energy purchased Consumers' first mortgage bonds with a principal balance of \$431 million in exchange for cash of \$293 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds resulted in a pre-tax gain of \$131 million for the year ended

December 31, 2023. Interest expense related to the repurchased bonds was \$5 million for the year ended December 31, 2023.

Regulatory Authorization for Financings: Consumers is required to maintain FERC authorization for financings. Any long-term issuances during the authorization period are exempt from FERC’s competitive bidding and negotiated placement requirements. Its short-term authorization ends on May 2, 2026. In January 2026, Consumers filed an application with FERC for authority to issue long-term and short-term debt securities between May 1, 2026 and April 30, 2028.

First Mortgage Bonds: Consumers secures its first mortgage bonds by a mortgage and lien on substantially all of its property. Consumers’ ability to issue first mortgage bonds is restricted by certain provisions in the First Mortgage Bond Indenture and the need for regulatory approvals under federal law. Restrictive issuance provisions in the First Mortgage Bond Indenture include achieving a two-times interest coverage ratio and having sufficient unfunded net property additions.

Securitization Bonds: Certain regulatory assets held by Consumers’ subsidiaries, Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding, collateralize Consumers’ securitization bonds. Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding are distinct subsidiaries. The bondholders of each entity have no recourse to the other’s assets or the assets of Consumers. Consumers collects securitization surcharges to cover the principal and interest on the bonds as well as certain other qualified costs. The surcharges collected by Consumers on behalf of each entity are remitted to that subsidiary’s account and are not available to creditors of Consumers or creditors of Consumers’ affiliates other than the subsidiary that issued the bonds.

Debt Maturities: At December 31, 2025, the aggregate annual maturities for long-term debt for the next five years, based on stated maturities or earlier put dates, were:

	<i>In Millions</i>				
	2026	2027	2028	2029	2030
CMS Energy, including Consumers					
<i>Long-term debt</i>					
CMS Energy, parent only	\$ 300	\$ 625	\$ 800	\$ —	\$ —
NorthStar Clean Energy	77	—	235	—	—
Consumers	573	263	843	1,256	812
Total CMS Energy	\$ 950	\$ 888	\$ 1,878	\$ 1,256	\$ 812
Consumers					
Long-term debt	\$ 573	\$ 263	\$ 843	\$ 1,256	\$ 812

Credit Facilities: The following credit facilities with banks were available at December 31, 2025:

<i>In Millions</i>				
Expiration Date	Amount of Facility	Amount Borrowed	Letters of Credit Outstanding	Amount Available
CMS Energy, parent only				
Unsecured revolving credit facility, expiring November 2030 ¹	\$ 750	\$ —	\$ 35	\$ 715
Unsecured letter of credit facility, expiring September 2026	50	—	50	—
NorthStar Clean Energy				
Secured revolving credit facility, expiring May 2028 ²	\$ 250	\$ 235	\$ 10	\$ 5
Secured letter of credit facility, expiring September 2028 ³	37	—	37	—
Secured letter of credit facility ⁴	19	—	12	7
Consumers				
Secured revolving credit facility, expiring November 2030 ^{5,6}	\$ 1,100	\$ —	\$ 6	\$ 1,094
Secured revolving credit facility, expiring November 2028 ^{5,6}	300	—	—	300
Secured letter of credit facility, expiring May 2027 ⁵	100	—	100	—
Unsecured letter of credit facility, expiring March 2028	50	—	43	7
Unsecured letter of credit facility ⁷	100	—	97	3
Unsecured letter of credit facility ⁷	100	—	100	—

¹ There were no borrowings under this facility during the year ended December 31, 2025.

² Obligations under this facility are secured by certain pledged equity interests in subsidiaries of NorthStar Clean Energy; under the terms of this facility, the interests may not be sold by NorthStar Clean Energy unless there is an agreed-upon substitution for the pledged equity interests. At December 31, 2025, the net book value of the pledged equity interests was \$514 million. Also under the terms of this facility, NorthStar Clean Energy may be restricted from remitting cash dividends to CMS Energy in the event of default.

³ This letter of credit facility is available to a subsidiary of Aviator Wind Equity Holdings and is secured by assets of Aviator Wind. For more information regarding Aviator Wind Equity Holdings and Aviator Wind, see Note 19, Variable Interest Entities.

⁴ The letter of credit facility is available to certain subsidiaries of NorthStar Clean Energy. The letter of credit facility is secured under a construction-to-term financing agreement and will expire five years after the term conversion date.

⁵ Obligations under these facilities are secured by first mortgage bonds of Consumers.

⁶ There were no borrowings under these facilities during the year ended December 31, 2025.

⁷ Uncommitted letter of credit facility with automatic renewal provisions and therefore no expiration.

Short-term Borrowings: Under Consumers’ commercial paper program, Consumers may issue, in one or more placements, investment-grade commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers’ revolving credit facilities and may have an aggregate principal amount outstanding of up to \$500 million. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At December 31, 2025, there were no commercial paper notes outstanding under this program.

In December 2025, Consumers renewed a short-term credit agreement with CMS Energy, permitting Consumers to borrow up to \$500 million at an interest rate of the prior month’s average one-month Term SOFR minus 0.100 percent. At December 31, 2025, outstanding borrowings under the agreement were \$340 million bearing interest at 3.859 percent, recorded as current notes payable – related parties on Consumers’ consolidated balance sheets.

NorthStar Clean Energy’s Supplier Financing Program: Under a supplier financing program, NorthStar Clean Energy agrees to pay a bank that is acting as its payment agent the stated amount of confirmed invoices from participating suppliers on the original maturity dates of the invoices. The bank is required to pay the supplier invoices that have been confirmed as valid under the program in full within 135 days of the invoice date. NorthStar Clean Energy does not provide collateral or a guarantee to the bank in support of its payment obligations under the agreement, nor does it pay a fee for the service. NorthStar Clean Energy or the bank may terminate the supplier financing program agreement upon 30 days prior written notice to the other party. Obligations under this program are accounted for in accounts payable on CMS Energy’s consolidated balance sheets.

Presented in the following table is the activity under NorthStar Clean Energy’s supplier financing program during the year ended December 31, 2025

Year Ended December 31	<i>In Millions</i>	
	2025	2024
Balance of payables under supplier financing program at beginning of period	\$ 22	\$ —
Payables confirmed	158	22
Payments and other adjustments	(102)	—
Balance of payables under supplier financing program at end of period	\$ 78	\$ 22

Dividend Restrictions: At December 31, 2025, payment of dividends by CMS Energy on its common stock was limited to \$8.9 billion under provisions of the Michigan Business Corporation Act of 1972.

Under the provisions of its articles of incorporation, at December 31, 2025, Consumers had \$2.5 billion of unrestricted retained earnings available to pay dividends on its common stock to CMS Energy. Provisions of the Federal Power Act and the Natural Gas Act appear to restrict dividends payable by Consumers to the amount of Consumers’ retained earnings. Several decisions from FERC suggest that, under a variety of circumstances, dividends from Consumers on its common stock would not be limited to amounts in Consumers’ retained earnings. Any decision by Consumers to pay dividends on its common stock in excess of retained earnings would be based on specific facts and circumstances and would be subject to a formal regulatory filing process.

During the year ended December 31, 2025, Consumers paid \$898 million in dividends on its common stock to CMS Energy.

Capitalization: The authorized capital stock of CMS Energy consists of:

- 350 million shares of CMS Energy Common Stock, par value \$0.01 per share
- 10 million shares of CMS Energy Preferred Stock, par value \$0.01 per share

Issuance of Common Stock: In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to \$1 billion in privately negotiated transactions, in “at the market” offerings, or through forward sales transactions.

Under the forward sales transactions, CMS Energy may either settle physically by issuing shares of its common stock at the then-applicable forward sale price specified by the agreement or settle net by delivering or receiving cash or shares. CMS Energy may settle the contracts at any time through their maturity dates, and presently intends to physically settle the contracts by delivering shares of its common stock.

As of December 31, 2024, CMS Energy had 0.4 million shares contracted under forward sale agreements at a weighted average initial forward price of \$69.43 per share. During the year ended December 31, 2025, CMS Energy entered into forward sale agreements for approximately 6.7 million shares at a weighted average initial forward price of \$71.08 per share. During the same period, CMS Energy settled forward sale contracts under this program by issuing approximately 7.0 million shares at a weighted average price of \$71.16 per share, resulting in net proceeds of \$497 million. Following these transactions, outstanding forward contracts under the program have an aggregate sales price of \$8 million, maturing November 30, 2026.

The initial forward price in the forward equity sale contracts includes a deduction for commissions and will be adjusted on a daily basis over the term based on an interest rate factor and decreased on certain dates by certain predetermined amounts to reflect expected dividend payments. No amounts are recorded on CMS Energy’s consolidated balance sheets until settlements of the forward equity sale contracts occur. If CMS Energy had elected to net share settle or net cash settle the contracts as of December 31, 2025, it would not have been required to deliver shares or pay cash.

Preferred Stock: CMS Energy’s Series C preferred stock is traded on the New York Stock Exchange under the symbol CMS PRC. Depositary shares represent a 1/1000th interest in a share of its Series C preferred stock. The Series C preferred stock has no maturity or mandatory redemption date and is not redeemable at the option of the holders. CMS Energy may, at its option, redeem the Series C preferred stock, in whole or in part, at any time on or after July 15, 2026. The Series C preferred stock ranks senior to CMS Energy’s common stock with respect to dividend rights and distribution rights upon liquidation. Presented in the following table are details of CMS Energy’s Series C preferred stock at December 31, 2025 and 2024:

	Depositary Share Par Value	Depositary Share Optional Redemption Price	Number of Depositary Shares Authorized	Number of Depositary Shares Outstanding
Cumulative, redeemable perpetual	\$ 25	\$ 25	9,200,000	9,200,000

Preferred Stock of Subsidiary: Consumers' preferred stock is traded on the New York Stock Exchange under the symbol CMS-PB. Presented in the following table are details of Consumers' preferred stock at December 31, 2025 and 2024:

	Par Value	Optional Redemption Price	Number of Shares Authorized	Number of Shares Outstanding
Cumulative, with no mandatory redemption	\$ 100	\$ 110	7,500,000	373,148

6: Fair Value Measurements

Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. When measuring fair value, CMS Energy and Consumers are required to incorporate all assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. A fair value hierarchy prioritizes inputs used to measure fair value according to their observability in the market. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 inputs are observable, market-based inputs, other than Level 1 prices. Level 2 inputs may include quoted prices for similar assets or liabilities in active markets, quoted prices in inactive markets, and inputs derived from or corroborated by observable market data.
- Level 3 inputs are unobservable inputs that reflect CMS Energy's or Consumers' own assumptions about how market participants would value their assets and liabilities.

CMS Energy and Consumers classify fair value measurements within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement in its entirety.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Presented in the following table are CMS Energy's and Consumers' assets and liabilities recorded at fair value on a recurring basis:

December 31	<i>In Millions</i>			
	CMS Energy, including Consumers		Consumers	
	2025	2024	2025	2024
<i>Assets¹</i>				
Cash equivalents	\$ 154	\$ 27	\$ —	\$ —
Restricted cash equivalents	106	75	86	75
Nonqualified deferred compensation plan assets	36	34	27	25
Derivative instruments	2	2	2	2
Total assets	\$ 298	\$ 138	\$ 115	\$ 102
<i>Liabilities¹</i>				
Nonqualified deferred compensation plan liabilities	\$ 36	\$ 34	\$ 27	\$ 25
Derivative instruments	3	—	—	—
Total liabilities	\$ 39	\$ 34	\$ 27	\$ 25

¹ All assets and liabilities were classified as Level 1 with the exception of derivative contracts, which were classified as Level 2 and 3.

Cash Equivalents: Cash equivalents and restricted cash equivalents consist of money market funds with daily liquidity.

Nonqualified Deferred Compensation Plan Assets and Liabilities: The nonqualified deferred compensation plan assets consist of mutual funds, which are bought and sold only at the discretion of plan participants. The assets are valued using the daily quoted net asset values. CMS Energy and Consumers value their nonqualified deferred compensation plan liabilities based on the fair values of the plan assets, as they reflect the amount owed to the plan participants in accordance with their investment elections. CMS Energy and Consumers report the assets in other non-current assets and the liabilities in other non-current liabilities on their consolidated balance sheets.

Derivative Instruments: CMS Energy and Consumers value their derivative instruments using either a market approach that incorporates information from market transactions, or an income approach that discounts future expected cash flows to a present value amount. CMS Energy's and Consumers' derivatives are classified as Level 2 and 3.

The derivatives classified as Level 2 are interest rate swaps at NorthStar Clean Energy, which are valued using market-based inputs.

In February 2025, a subsidiary of NorthStar Clean Energy entered into floating-to-fixed interest rate swaps to reduce the impact of interest rate fluctuations associated with interest payments on certain future long-term variable-rate debt. The interest rate swaps economically hedge the future variability of interest payments on debt with a notional amount of \$109 million. Gains or losses on these swaps are reported in other expense on CMS Energy's consolidated statements of income. The amount recorded in other expense was \$3 million for the year ended December 31, 2025. The fair value of these swaps recorded in

other non-current liabilities on CMS Energy's consolidated balance sheets totaled \$3 million at December 31, 2025.

The majority of derivatives classified as Level 3 are FTRs held by Consumers. Due to the lack of quoted pricing information, Consumers determines the fair value of its FTRs based on Consumers' average historical settlements. Consumers reports derivatives associated with FTRs in other current assets on its consolidated balance sheets. There was no material activity within the Level 3 category of derivatives during the periods presented.

7: Financial Instruments

Presented in the following table are the carrying amounts and fair values, by level within the fair value hierarchy, of CMS Energy's and Consumers' financial instruments that are not recorded at fair value. The table excludes cash, cash equivalents, short-term financial instruments, and trade accounts receivable and payable whose carrying amounts approximate their fair values. For information about assets and liabilities recorded at fair value and for additional details regarding the fair value hierarchy, see Note 6, Fair Value Measurements.

<i>In Millions</i>											
	December 31, 2025					December 31, 2024					
	Carrying Amount	Fair Value				Carrying Amount	Fair Value				
		Total	Level				Total	Level			
			1	2	3			1	2	3	
CMS Energy, including Consumers											
<i>Assets</i>											
Long-term receivables ¹	\$ 7	\$ 6	\$ —	\$ —	\$ 6	\$ 9	\$ 8	\$ —	\$ —	\$ 8	
<i>Liabilities</i>											
Long-term debt ²	18,757	17,645	2,042	13,663	1,940	16,386	14,876	1,018	11,952	1,906	
Long-term payables ³	7	7	—	—	7	9	9	—	—	9	
Consumers											
<i>Assets</i>											
Long-term receivables ¹	\$ 7	\$ 6	\$ —	\$ —	\$ 6	\$ 9	\$ 8	\$ —	\$ —	\$ 8	
Notes receivable – related party ⁴	90	90	—	—	90	94	94	—	—	94	
<i>Liabilities</i>											
Long-term debt ⁵	12,097	11,031	—	9,091	1,940	11,270	9,940	—	8,034	1,906	
Long-term debt – related party ⁶	1,005	657	—	657	—	823	549	—	549	—	
Long-term payables	2	2	—	—	2	4	4	—	—	4	

¹ Includes current portion of long-term accounts receivable and notes receivable of \$3 million at December 31, 2025 and \$4 million at December 31, 2024.

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- ² Includes current portion of long-term debt of \$950 million at December 31, 2025 and \$1.2 billion at December 31, 2024.
- ³ Includes current portion of long-term payables of \$2 million at December 31, 2025 and 2024.
- ⁴ Includes current portion of notes receivable – related party of \$7 million at December 31, 2025 and 2024. For more information on notes receivable – related party, see Note 18, Related-party Transactions—Consumers
- ⁵ Includes current portion of long-term debt of \$573 million at December 31, 2025 and \$452 million at December 31, 2024.
- ⁶ For more information on CMS Energy’s repurchases of Consumers’ first mortgage bonds, see Note 5, Financings and Capitalization—CMS Energy’s Purchase of Consumers’ First Mortgage Bonds.

Notes receivable – related party represents Consumers’ portion of the DB SERP demand note payable issued by CMS Energy to the DB SERP rabbi trust. The demand note bears interest at an annual rate of 4.10 percent and has a maturity date of 2028.

8: Plant, Property, and Equipment

Presented in the following table are details of CMS Energy's and Consumers' plant, property, and equipment:

In Millions, Except as Noted

December 31	Estimated Depreciable Life in Years	2025	2024
CMS Energy, including Consumers			
<i>Plant, property, and equipment, gross</i>			
Consumers	3 – 125	\$ 36,120	\$ 33,434
<i>NorthStar Clean Energy</i>			
Independent power production ¹	3 – 40	1,585	1,452
Assets under finance leases ²		55	45
Other	3 – 5	3	1
Plant, property, and equipment, gross		\$ 37,763	\$ 34,932
Construction work in progress		3,052	2,098
Accumulated depreciation and amortization		(10,135)	(9,569)
Total plant, property, and equipment³		\$ 30,680	\$ 27,461
Consumers			
<i>Plant, property, and equipment, gross</i>			
<i>Electric</i>			
Generation ⁴	15 – 125	\$ 7,171	\$ 6,576
Distribution	15 – 75	13,360	12,135
Other	5 – 55	1,209	1,307
Assets under finance leases ²		131	119
<i>Gas</i>			
Distribution	20 – 85	8,553	7,942
Transmission	17 – 75	3,236	3,081
Underground storage facilities ⁵	29 – 75	1,535	1,405
Other	5 – 55	886	828
Assets under finance leases ²		8	12
Other non-utility property	3 – 51	31	29
Plant, property, and equipment, gross		\$ 36,120	\$ 33,434
Construction work in progress ⁶		2,354	1,766
Accumulated depreciation and amortization		(9,842)	(9,310)
Total plant, property, and equipment³		\$ 28,632	\$ 25,890

¹ A portion of independent power production assets are leased to others under operating leases. For information regarding CMS Energy's operating leases of owned assets, see Note 9, Leases.

² For information regarding the amortization terms of CMS Energy's and Consumers' assets under finance leases, see Note 9, Leases.

³ Consumers' plant additions were \$3.1 billion for the year ended December 31, 2025 and \$2.1 billion for the year ended December 31, 2024. Consumers' plant retirements were \$387 million for the year ended December 31, 2025 and \$390 million for the year ended December 31, 2024.

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- 4 Includes 13 hydroelectric dams that Consumers has agreed to sell, contingent upon MPSC and FERC approval. For more information, see Note 20, Exit Activities and Asset Sales.
- 5 Underground storage includes base natural gas of \$24 million at December 31, 2025 and \$26 million for the year ended December 31, 2024. Base natural gas is not subject to depreciation.
- 6 For the year ended December 31, 2025, Consumers fully impaired certain development assets totaling \$20 million. Of this amount, \$15 million relates to two early-phase renewable natural gas development projects that have been paused indefinitely. The remaining impairment charge was deferred as a regulatory asset and will be recovered through the Renewable Energy Plan.

Intangible Assets: Included in net plant, property, and equipment are intangible assets. Presented in the following table are details about Consumers' intangible assets:

In Millions, Except as Noted

Description	Amortization Life in Years	December 31, 2025		December 31, 2024		
		Gross Cost ¹	Accumulated Amortization	Gross Cost ¹	Accumulated Amortization	
Consumers						
Software development	3 – 15	\$ 649	\$ 492	\$ 679	\$ 481	
Rights of way	50 – 85	274	72	253	68	
Franchises and consents	5 – 50	16	12	16	11	
Leasehold improvements	various ²	15	9	13	7	
Other intangibles	various	33	17	28	16	
Total		\$ 987	\$ 602	\$ 989	\$ 583	

¹ Consumers' intangible asset additions were \$62 million for the year ended December 31, 2025 and \$90 million for the year ended December 31, 2024. Consumers' intangible asset retirements were \$64 million for the year ended December 31, 2025 and \$153 million for the year ended December 31, 2024.

² Leasehold improvements are amortized over the life of the lease, which may change whenever the lease is renewed or extended.

Capitalization: CMS Energy and Consumers record plant, property, and equipment at original cost when placed into service. The cost includes labor, material, applicable taxes, overhead such as pension and other benefits, and AFUDC, if applicable. Consumers' plant, property, and equipment is generally recoverable through its general ratemaking process.

With the exception of utility property for which the remaining book value has been securitized, mothballed utility property stays in rate base and continues to be depreciated at the same rate as before the mothball period. When utility property is retired or otherwise disposed of in the ordinary course of business, Consumers records the original cost to accumulated depreciation, along with associated cost of removal, net of salvage. CMS Energy and Consumers recognize gains or losses on the retirement or disposal of non-regulated assets in income. Consumers records cost of removal collected from customers, but not spent, as a regulatory liability.

Software: CMS Energy and Consumers capitalize the costs to purchase and develop internal-use computer software. These costs are expensed evenly over the estimated useful life of the internal-use computer software. If computer software is integral to computer hardware, then its cost is capitalized and depreciated with the hardware.

AFUDC: Consumers capitalizes AFUDC on regulated major construction projects. AFUDC represents the estimated cost of debt and authorized return-on-equity funds used to finance construction additions. Consumers records the offsetting credit as a reduction of interest for the amount representing the borrowed funds component and as other income for the equity funds component on the consolidated statements of income. When construction is completed and the property is placed in service, Consumers depreciates and recovers the capitalized AFUDC from customers over the life of the related asset. Presented in the following table are Consumers' average AFUDC capitalization rates:

Years Ended December 31	2025	2024	2023
Electric	6.9%	6.9%	6.5%
Gas	5.9	5.8	5.8

Assets Under Finance Leases: Presented in the following table are further details about changes in CMS Energy's and Consumers' assets under finance leases:

	<i>In Millions</i>	
Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Balance at beginning of period	\$ 176	\$ 136
Additions	53	55
Net retirements and other adjustments	(36)	(15)
Balance at end of period	\$ 193	\$ 176
Consumers		
Balance at beginning of period	\$ 131	\$ 112
Additions	22	34
Net retirements and other adjustments	(15)	(15)
Balance at end of period	\$ 138	\$ 131

Assets under finance leases are presented as gross amounts. CMS Energy's, including Consumers', accumulated amortization of assets under finance leases was \$53 million at December 31, 2025 and \$57 million at December 31, 2024. Consumers' accumulated amortization of assets under finance leases was \$48 million at December 31, 2025 and \$55 million at December 31, 2024.

Depreciation and Amortization: Presented in the following table are further details about CMS Energy's and Consumers' accumulated depreciation and amortization:

	<i>In Millions</i>	
Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Utility plant assets	\$ 9,838	\$ 9,307
Non-utility plant assets	297	262
Consumers		
Utility plant assets	\$ 9,838	\$ 9,307
Non-utility plant assets	4	3

Consumers depreciates utility property on an asset-group basis, in which it applies a single MPSC-approved depreciation rate to the gross investment in a particular class of property within the electric and

gas segments. Consumers performs depreciation studies periodically to determine appropriate group lives. Presented in the following table are the composite depreciation rates for Consumers' segment properties:

Years Ended December 31	2025	2024	2023
Electric utility property	3.6%	3.6%	3.8%
Gas utility property	2.5	2.5	2.8
Other property	7.0	7.1	7.8

CMS Energy and Consumers record property repairs and minor property replacement as maintenance expense. CMS Energy and Consumers record planned major maintenance activities as operating expense unless the cost represents the acquisition of additional long-lived assets or the replacement of an existing long-lived asset.

Presented in the following table are the components of CMS Energy's and Consumers' depreciation and amortization expense:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Depreciation expense – plant, property, and equipment	\$ 1,099	\$ 1,041	\$ 1,050
<i>Amortization expense</i>			
Software	75	81	92
Other intangible assets	7	5	5
Other regulatory assets	8	2	—
Securitized regulatory assets	117	111	33
Total depreciation and amortization expense	\$ 1,306	\$ 1,240	\$ 1,180
Consumers			
Depreciation expense – plant, property, and equipment	\$ 1,047	\$ 992	\$ 1,007
<i>Amortization expense</i>			
Software	75	81	92
Other intangible assets	7	5	5
Other regulatory assets	8	2	—
Securitized regulatory assets	117	111	33
Total depreciation and amortization expense	\$ 1,254	\$ 1,191	\$ 1,137

Presented in the following table is Consumers' estimated amortization expense on intangible assets for each of the next five years:

	<i>In Millions</i>				
	2026	2027	2028	2029	2030
Consumers					
Intangible asset amortization expense	\$ 77	\$ 66	\$ 55	\$ 50	\$ 49

Jointly Owned Regulated Utility Facilities

Presented in the following table are Consumers' investments in jointly owned regulated utility facilities at December 31, 2025:

	<i>In Millions, Except Ownership Share</i>		
	J.H. Campbell Unit 3	Ludington	Other
Ownership share	93.3%	51.0%	various
Utility plant in service	\$ 1,726	\$ 620	\$ 481
Accumulated provision for depreciation	(916)	(253)	(97)
Plant under construction	—	37	17
Net investment	\$ 810	\$ 404	\$ 401

Consumers includes its share of the direct expenses of the jointly owned plants in operating expenses. Consumers shares operation, maintenance, and other expenses of these jointly owned utility facilities in proportion to each participant's undivided ownership interest. Consumers is required to provide only its share of financing for the jointly owned utility facilities.

Consumers plans to retire J.H. Campbell and, in 2022, removed an amount representing the projected remaining book value of the electric generating units upon their retirement from total plant, property, and equipment and recorded it as a regulatory asset on its consolidated balance sheets. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For additional details, see Note 3, Regulatory Matters.

Consumers and DTE Electric engaged in litigation with TAES and Toshiba related to TAES' incomplete, defective, and nonconforming work during a major overhaul and upgrade of Ludington. For additional details on this dispute, see Note 4, Contingencies and Commitments—Ludington Overhaul Contract Dispute.

9: Leases

Lessee

CMS Energy and Consumers lease various assets from third parties, including coal-carrying railcars, real estate, service vehicles, and gas pipeline capacity. In addition, CMS Energy and Consumers account for several of their PPAs as leases.

CMS Energy and Consumers do not record right-of-use assets or lease liabilities on their consolidated balance sheets for rentals with lease terms of 12 months or less, most of which are for the lease of real estate and service vehicles. Lease expense for these rentals is recognized on a straight-line basis over the lease term.

CMS Energy and Consumers include future payments for all renewal options, fair market value extensions, and buyout provisions reasonably certain of exercise in their measurement of lease right-of-use assets and lease liabilities. In addition, certain leases for service vehicles contain end-of-lease adjustment clauses based on proceeds received from the sale or disposition of the vehicles. CMS Energy and Consumers also include executory costs in the measurement of their right-of-use assets and lease liabilities, except for maintenance costs related to their coal-carrying railcar leases.

Most of Consumers' PPAs contain provisions at the end of the initial contract terms to renew the agreements annually under mutually agreed-upon terms at the time of renewal. Energy and capacity payments that vary depending on quantities delivered are recognized as variable lease costs when incurred. Consumers accounts for a PPA with one of CMS Energy's equity method subsidiaries as a finance lease.

Presented in the following table is information about CMS Energy's and Consumers' lease right-of-use assets and lease liabilities:

In Millions, Except as Noted

December 31	CMS Energy, including Consumers		Consumers	
	2025	2024	2025	2024
<i>Operating leases</i>				
Right-of-use assets ¹	\$ 22	\$ 24	\$ 18	\$ 20
<i>Lease liabilities</i>				
Current lease liabilities ²	3	3	3	3
Non-current lease liabilities ³	19	21	15	17
<i>Finance leases</i>				
Right-of-use assets	140	119	90	76
<i>Lease liabilities⁴</i>				
Current lease liabilities	6	4	6	4
Non-current lease liabilities	135	112	81	69
<i>Weighted-average remaining lease term (in years)</i>				
Operating leases	20	20	20	19
Finance leases	24	26	19	22
<i>Weighted-average discount rate</i>				
Operating leases	5.3%	5.3%	5.4%	5.4%
Finance leases ⁵	5.9%	5.8%	4.9%	4.8%

¹ CMS Energy's and Consumers' operating right-of-use lease assets are reported as other non-current assets on their consolidated balance sheets.

² The current portion of CMS Energy's and Consumers' operating lease liabilities are reported as other current liabilities on their consolidated balance sheets.

³ The non-current portion of CMS Energy's and Consumers' operating lease liabilities are reported as other non-current liabilities on their consolidated balance sheets.

⁴ Includes related-party lease liabilities of \$22 million, of which \$1 million was current, at December 31, 2025 and 2024.

⁵ This rate excludes the impact of Consumers' pipeline agreements and long-term PPAs accounted for as finance leases. The required capacity payments under these agreements, when compared to the underlying fair value of the leased assets, result in effective interest rates that exceed market rates for leases with similar terms.

CMS Energy and Consumers report operating, variable, and short-term lease costs as operating expenses on their consolidated statements of income, except for certain amounts that may be capitalized to other assets. Presented in the following table is a summary of CMS Energy's and Consumers' total lease costs:

	<i>In Millions</i>	
Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Operating lease costs	\$ 4	\$ 6
<i>Finance lease costs</i>		
Amortization of right-of-use assets	8	6
Interest on lease liabilities	18	16
Variable lease costs	115	107
Short-term lease costs	25	13
Total lease costs	\$ 170	\$ 148
Consumers		
Operating lease costs	\$ 4	\$ 5
<i>Finance lease costs</i>		
Amortization of right-of-use assets	6	5
Interest on lease liabilities	14	13
Variable lease costs	115	107
Short-term lease costs	24	12
Total lease costs	\$ 163	\$ 142

Presented in the following table is supplemental cash flow information related to CMS Energy's and Consumers' lease liabilities:

	<i>In Millions</i>	
Years Ended December 31	2025	2024
CMS Energy, including Consumers		
<i>Cash paid for amounts included in the measurement of lease liabilities</i>		
Cash used in operating activities for operating leases	\$ 4	\$ 6
Cash used in operating activities for finance leases	17	15
Cash used in financing activities for finance leases	5	6
<i>Lease liabilities arising from obtaining right-of-use assets</i>		
Operating leases	1	3
Finance leases	22	55
Consumers		
<i>Cash paid for amounts included in the measurement of lease liabilities</i>		
Cash used in operating activities for operating leases	\$ 4	\$ 5
Cash used in operating activities for finance leases	14	13
Cash used in financing activities for finance leases	6	5
<i>Lease liabilities arising from obtaining right-of-use assets</i>		
Operating leases	1	1
Finance leases	22	34

Presented in the following table are the minimum rental commitments under CMS Energy's and Consumers' non-cancelable leases:

December 31, 2025	<i>In Millions</i>			
	Operating Leases	Finance Leases		Total
		Pipelines and PPAs	Land and Other	
CMS Energy, including Consumers				
2026	\$ 4	\$ 17	\$ 6	\$ 23
2027	2	17	6	23
2028	2	17	5	22
2029	2	17	6	23
2030	1	17	6	23
2031 and thereafter	27	2	200	202
Total minimum lease payments	\$ 38	\$ 87	\$ 229	\$ 316
Less discount	16	42	133	175
Present value of minimum lease payments	\$ 22	\$ 45	\$ 96	\$ 141
Consumers				
2026	\$ 4	\$ 17	\$ 3	\$ 20
2027	2	17	3	20
2028	1	17	2	19
2029	1	17	2	19
2030	1	17	2	19
2031 and thereafter	22	2	72	74
Total minimum lease payments	\$ 31	\$ 87	\$ 84	\$ 171
Less discount	13	42	42	84
Present value of minimum lease payments	\$ 18	\$ 45	\$ 42	\$ 87

Lessor

CMS Energy and Consumers are the lessor under power sales and natural gas delivery agreements that are accounted for as leases.

CMS Energy has power sales agreements that are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. For the year ended December 31, 2025, lease revenue from these power sales agreements was \$149 million, which included variable lease payments of \$105 million. For the year ended December 31, 2024, lease revenue from these power sales agreements was \$105 million, which included variable lease payments of \$61 million. These non-cancelable operating leases expire in 2026; remaining minimum rental payments amount to \$18 million.

Consumers has a natural gas transportation agreement with a subsidiary of CMS Energy that extends through 2038, related to a pipeline owned by Consumers. This agreement is accounted for as a direct finance lease and will automatically extend annually unless terminated by either party. The effects of the lease are eliminated on CMS Energy's consolidated financial statements.

Minimum rental payments to be received under Consumers' direct financing lease are \$1 million for each of the next five years and \$6 million for the years thereafter. The lease receivable was \$5 million as of December 31, 2025, which does not include unearned income of \$5 million.

10: Asset Retirement Obligations

CMS Energy and Consumers record the fair value of the cost to remove assets at the end of their useful lives, if there is a legal obligation to remove them. If a reasonable estimate of fair value cannot be made in the period in which the ARO is incurred, such as for assets with indeterminate lives, the liability is recognized when a reasonable estimate of fair value can be made. CMS Energy and Consumers have not recorded liabilities associated with the closure of their hydroelectric facilities and certain gas wells that have an indeterminate life or for assets that have immaterial cumulative disposal costs, such as substation batteries.

CMS Energy and Consumers calculate the fair value of ARO liabilities using an expected present-value technique that reflects assumptions about costs and inflation, and uses a credit-adjusted risk-free rate to discount the expected cash flows. CMS Energy's ARO liabilities are primarily at Consumers.

Presented below are the categories of assets that CMS Energy and Consumers have legal obligations to remove at the end of their useful lives and for which they have an ARO liability recorded:

ARO Description	Long-lived Assets
Closure of coal ash disposal areas	Generating plants coal ash areas
Gas distribution cut, purge, and cap	Gas distribution mains and services
Asbestos abatement	Electric and gas utility plant
Closure of renewable generation assets	Wind and solar generation facilities
Capping and partial filling of water intake line	Generating plant water intake line
Gas wells plug and abandon	Gas transmission and storage

In May 2024, the EPA finalized a rule regulating CCR impoundments at electric generating facilities that became inactive prior to the effective date of a rule published in 2015 regulating CCRs under RCRA. Additionally, the EPA established groundwater monitoring, corrective action, closure, and post-closure care requirements for CCR surface impoundments and landfills closed prior to the effective date of the 2015 CCR rule, but that do not meet the closure technical and performance standards of the May 2024 rule. These include inactive CCR landfills that were previously exempted from regulation but that are now considered CCR management units.

In response to the new rule, Consumers has been performing its review of legacy impoundments and of other aspects of the 2024 rule in accordance with the timelines prescribed by the rule, including the requirement to determine and report the presence of any CCR management units to the EPA by February 2027. Consumers has been recording incremental AROs for legacy impoundments and CCR management units when a reasonable estimate of the fair value of the associated costs can be made, and the ultimate amount of any resulting ARO could be material. In February 2026, the EPA issued a final rule extending the compliance milestone schedule for CCR management units. This extension does not have a material impact on Consumers' compliance strategy. Consumers has historically been authorized to recover in electric rates costs related to coal ash disposal sites.

Presented in the following tables are the changes in CMS Energy's and Consumers' ARO liabilities:

In Millions

Company and ARO Description	ARO Liability 12/31/2024	Incurred	Settled	Accretion	Cash Flow Revisions	ARO Liability 12/31/2025
CMS Energy, including Consumers						
Consumers	\$ 694	\$ 27	\$ (73)	\$ 32	\$ 73	\$ 753
Renewable generation assets	34	4	—	1	—	39
Total CMS Energy	\$ 728	\$ 31	\$ (73)	\$ 33	\$ 73	\$ 792
Consumers						
Coal ash disposal areas	\$ 230	\$ —	\$ (37)	\$ 10	\$ 60 ¹	\$ 263
Gas distribution cut, purge, and cap	295	10	(13)	15	—	307
Asbestos abatement	37	—	(2)	2	—	37
Renewable generation assets	105	17	—	3	—	125
Generating plant water intake line	—	—	—	1	18 ²	19
Gas wells plug and abandon	27	—	(21)	1	(5)	2
Total Consumers	\$ 694	\$ 27	\$ (73)	\$ 32	\$ 73	\$ 753

¹ The increase in the AROs associated with coal ash disposal areas was primarily the result of incremental remedies required by EGLE for certain ash disposal ponds and incremental AROs recorded in response to reviews of legacy CCR impoundments.

² The increase in AROs associated with water intake lines, which were previously immaterial, was primarily the result of changes in the expected scope of required capping following the finalization of decommissioning plans with the local jurisdiction.

In Millions

Company and ARO Description	ARO Liability 12/31/2023	Incurred	Settled	Accretion	Cash Flow Revisions	ARO Liability 12/31/2024
CMS Energy, including Consumers						
Consumers	\$ 739	\$ 1	\$ (69)	\$ 33	\$ (10)	\$ 694
Renewable generation assets	32	—	—	2	—	34
Total CMS Energy	\$ 771	\$ 1	\$ (69)	\$ 35	\$ (10)	\$ 728
Consumers						
Coal ash disposal areas	\$ 268	\$ 1	\$ (51)	\$ 12	\$ —	\$ 230
Gas distribution cut, purge, and cap	290	—	(9)	15	(1)	295
Asbestos abatement	51	—	(7)	2	(9)	37
Renewable generation assets	102	—	—	3	—	105
Gas wells plug and abandon	28	—	(2)	1	—	27
Total Consumers	\$ 739	\$ 1	\$ (69)	\$ 33	\$ (10)	\$ 694

11: Retirement Benefits

Benefit Plans: CMS Energy and Consumers provide pension, OPEB, and other retirement benefits to eligible employees under a number of different plans. These plans include:

- non-contributory, qualified DB Pension Plans (closed to new non-union participants as of July 1, 2003 and closed to new union participants as of September 1, 2005)
- a non-contributory, qualified DCCP for employees hired on or after July 1, 2003
- benefits to certain management employees under a non-contributory, nonqualified DB SERP (closed to new participants as of March 31, 2006)
- a non-contributory, nonqualified DC SERP for certain management employees hired or promoted on or after April 1, 2006
- a contributory, qualified defined contribution 401(k) plan
- health care and life insurance benefits under an OPEB Plan

DB Pension Plans: Participants in the pension plans include present and former employees of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries. Pension plan trust assets are not distinguishable by company. Effective December 31, 2017, CMS Energy’s and Consumers’ then-existing pension plan was amended to include only retired and former employees already covered; this amended plan is referred to as DB Pension Plan B. Also effective December 31, 2017, active employees were moved to a newly created pension plan, referred to as DB Pension Plan A, whose benefits mirror those provided under DB Pension Plan B. Maintaining separate plans for the two groups allows CMS Energy and Consumers to employ a more targeted investment strategy and provides additional opportunities to mitigate risk and volatility.

DCCP: CMS Energy and Consumers provide an employer contribution to the DCCP 401(k) plan for employees hired on or after July 1, 2003. The contribution ranges from 5 percent to 10 percent of base pay, depending on years of service and employee class. Employees are not required to contribute in order to receive the plan’s employer contribution. DCCP expense for CMS Energy, including Consumers, was \$57 million for the year ended December 31, 2025, \$53 million for the year ended December 31, 2024, and \$51 million for the year ended December 31, 2023. DCCP expense for Consumers was \$55 million for the year ended December 31, 2025, \$52 million for the year ended December 31, 2024, and \$50 million for the year ended December 31, 2023.

DB SERP: The DB SERP is a nonqualified plan as defined by the Internal Revenue Code. DB SERP benefits are paid from a rabbi trust. The trust assets are not considered plan assets under ASC 715. DB SERP rabbi trust earnings are taxable. Presented in the following table are the fair values of trust assets and ABO for CMS Energy’s and Consumers’ DB SERP:

Years Ended December 31	<i>In Millions</i>	
	2025	2024
CMS Energy, including Consumers		
Trust assets	\$ 122	\$ 127
ABO	104	105
Consumers		
Trust assets	\$ 92	\$ 95
ABO	76	76

Neither CMS Energy nor Consumers made any contributions to the DB SERP in 2025 or 2024.

DC SERP: On April 1, 2006, CMS Energy and Consumers implemented a DC SERP and froze further new participation in the DB SERP. The DC SERP provides participants benefits ranging from 5 percent to 15 percent of total compensation. The DC SERP requires a minimum of five years of participation before vesting. CMS Energy's and Consumers' contributions to the plan, if any, are placed in a grantor trust. For CMS Energy and Consumers, trust assets were \$18 million at December 31, 2025 and \$17 million at December 31, 2024. DC SERP assets are included in other non-current assets on CMS Energy's and Consumers' consolidated balance sheets. CMS Energy's and Consumers' DC SERP expense was \$1 million for the years ended December 31, 2025, 2024, and 2023.

401(k) Plan: The 401(k) plan employer match equals 4 to 6 percent of employee eligible contributions based on an employee's wages and class. The total 401(k) plan cost for CMS Energy, including Consumers, was \$46 million for the year ended December 31, 2025, and \$41 million for the years ended December 31, 2024 and 2023. The total 401(k) plan cost for Consumers was \$44 million for the year ended December 31, 2025, \$39 million for the year ended December 31, 2024, and \$40 million for the year ended December 31, 2023.

Health-related OPEB Plan: Participants in the health-related OPEB Plan include regular full-time employees covered by the employee health care plan on the day before retirement from either CMS Energy or Consumers at age 55 or older with at least ten full years of applicable continuous service and hired before January 1, 2007 for non-union participants and hired before September 1, 2010 for union participants. Regular full-time employees who qualify for disability retirement under the DB Pension Plans or are disabled and covered by the DCCP and who have 15 years of applicable continuous service may also participate in the health-related OPEB Plan if hired before January 1, 2007 for non-union participants and hired before September 1, 2010 for union participants. Retiree health care costs were based on the assumption that costs would increase 8.00 percent in 2026 and 8.50 percent in 2025 for those under 65 and would increase 9.75 percent in 2026 and 10.25 percent in 2025 for those over 65. The rate of increase was assumed to decline to 4.75 percent by 2034 and thereafter for all retirees.

Assumptions: Presented in the following table are the weighted-average assumptions used in CMS Energy's, including Consumers', retirement benefit plans to determine benefit obligations and net periodic benefit cost:

December 31	2025	2024	2023
<i>Weighted average for benefit obligations¹</i>			
<i>Discount rate²</i>			
DB Pension Plan A	5.58%	5.73%	5.05%
DB Pension Plan B	5.28	5.59	4.95
DB SERP	5.22	5.56	4.94
OPEB Plan	5.50	5.69	5.02
<i>Rate of compensation increase</i>			
DB Pension Plan A	3.70	3.70	3.60
<i>Weighted average for net periodic benefit cost¹</i>			
<i>Service cost discount rate^{2,3}</i>			
DB Pension Plan A	5.77%	5.08%	5.27%
DB SERP ⁴	—	—	5.18
OPEB Plan	5.85	5.12	5.31
<i>Interest cost discount rate^{2,3}</i>			
DB Pension Plan A	5.43	4.93	5.12
DB Pension Plan B	5.30	4.87	5.06
DB SERP	5.29	4.87	5.06
OPEB Plan	5.39	4.91	5.10
<i>Expected long-term rate of return on plan assets⁵</i>			
DB Pension Plans	7.30	7.50	7.20
OPEB Plan	7.15	7.50	7.20
<i>Rate of compensation increase</i>			
DB Pension Plan A	3.70	3.60	3.60
DB SERP ⁴	—	—	5.50

- ¹ The mortality assumption for benefit obligations and net periodic benefit cost was based on the Pri-2012 Mortality Table, with improvement scale MP-2021.
- ² The discount rate reflects the rate at which benefits could be effectively settled and is equal to the equivalent single rate resulting from a yield-curve analysis. This analysis incorporated the projected benefit payments specific to CMS Energy's and Consumers' DB Pension Plans and OPEB Plan and the yields on high-quality corporate bonds rated Aa or better.
- ³ CMS Energy and Consumers have elected to use a full-yield-curve approach in the estimation of service cost and interest cost; this approach applies individual spot rates along the yield curve to future projected benefit payments based on the time of payment.
- ⁴ The last active participant in the DB SERP retired in 2023. Thus, the determination of the associated net periodic benefit cost no longer assumes a service cost discount rate nor a rate of compensation increase.
- ⁵ CMS Energy and Consumers determined the long-term rate of return using historical market returns, the present and expected future economic environment, the capital market principles of risk and return, and the expert opinions of individuals and firms with financial market knowledge. CMS Energy and Consumers considered the asset allocation of the portfolio in forecasting the future expected total return of the portfolio. The goal was to determine a long-term rate of return that could be incorporated into the planning

of future cash flow requirements in conjunction with the change in the liability. Annually, CMS Energy and Consumers review for reasonableness and appropriateness the forecasted returns for various classes of assets used to construct an expected return model. CMS Energy's and Consumers' expected long-term rate of return on the assets of the DB Pension Plans was 7.30 percent in 2025. The actual return on the assets of the DB Pension Plans was 12.7 percent in 2025, 3.6 percent in 2024, and 12.6 percent in 2023.

Costs: Presented in the following table are the costs (credits) and other changes in plan assets and benefit obligations incurred in CMS Energy's and Consumers' retirement benefit plans:

Years Ended December 31	<i>In Millions</i>					
	DB Pension Plans and DB SERP			OPEB Plan		
	2025	2024	2023	2025	2024	2023
CMS Energy, including Consumers						
<i>Net periodic credit</i>						
Service cost	\$ 25	\$ 28	\$ 29	\$ 8	\$ 11	\$ 12
Interest cost	114	109	112	43	43	44
Expected return on plan assets	(229)	(234)	(220)	(111)	(115)	(103)
<i>Amortization of:</i>						
Net loss	11	12	12	3	4	12
Prior service cost (credit)	4	4	4	(34)	(31)	(41)
Settlement loss	11	11	11	—	—	—
Net periodic credit	\$ (64)	\$ (70)	\$ (52)	\$ (91)	\$ (88)	\$ (76)
Consumers						
<i>Net periodic credit</i>						
Service cost	\$ 24	\$ 27	\$ 28	\$ 8	\$ 11	\$ 11
Interest cost	106	102	105	42	41	42
Expected return on plan assets	(215)	(221)	(208)	(104)	(107)	(95)
<i>Amortization of:</i>						
Net loss	10	11	11	3	4	12
Prior service cost (credit)	4	4	4	(33)	(30)	(40)
Settlement loss	11	11	11	—	—	—
Net periodic credit	\$ (60)	\$ (66)	\$ (49)	\$ (84)	\$ (81)	\$ (70)

In Consumers' electric and gas rate cases, the MPSC approved a mechanism allowing Consumers to defer for future recovery or refund pension and OPEB expenses above or below the amounts used to set existing rates. Amounts deferred will be collected from or refunded to customers over ten years. At December 31, 2025, CMS Energy, including Consumers, had deferred \$3 million of pension costs and \$6 million of OPEB credits under this mechanism related to 2025 expense. At December 31, 2024, CMS Energy, including Consumers, had deferred \$15 million of pension credits and \$11 million of OPEB credits under this mechanism related to 2024 expense. At December 31, 2023, CMS Energy, including Consumers, had deferred \$11 million of pension credits and \$23 million of OPEB costs under this mechanism related to 2023 expense.

CMS Energy and Consumers amortize net gains and losses in excess of 10 percent of the greater of the PBO or the MRV over the average remaining service period for DB Pension Plan A and the OPEB Plan and over the average remaining life expectancy of participants for DB Pension Plan B. For DB Pension Plan A, the estimated period of amortization of gains and losses was seven years for the year ended December 31, 2025, and eight years for the years ended December 31, 2024 and 2023. For DB Pension Plan B, the estimated period of amortization of gains and losses was 17 years for the years ended

December 31, 2025, 2024, and 2023. For the OPEB Plan, the estimated amortization period was nine years for the years ended December 31, 2025, 2024, and 2023.

Prior service cost (credit) amortization is established in the year in which the prior service cost (credit) first occurred, and is based on the same amortization period for all future years until the prior service cost (credit) is fully amortized. CMS Energy and Consumers had new prior service costs for OPEB in 2024. The estimated period of amortization of these new prior service costs is seven years.

CMS Energy and Consumers determine the MRV for the assets of the DB Pension Plans as the fair value of plan assets on the measurement date, adjusted by the gains or losses that will not be admitted into the MRV until future years. CMS Energy and Consumers reflect each year's gain or loss in the MRV in equal amounts over a five-year period beginning on the date the original amount was determined. CMS Energy and Consumers determine the MRV for OPEB Plan assets as the fair value of assets on the measurement date.

Reconciliations: Presented in the following table are reconciliations of the funded status of CMS Energy's and Consumers' retirement benefit plans with their retirement benefit plans' liabilities:

	<i>In Millions</i>					
	DB Pension Plans		DB SERP		OPEB Plan	
Years Ended December 31	2025	2024	2025	2024	2025	2024
CMS Energy, including Consumers						
Benefit obligation at beginning of period	\$ 2,094	\$ 2,195	\$ 105	\$ 114	\$ 831	\$ 900
Service cost	25	28	—	—	8	11
Interest cost	109	104	5	5	43	43
Plan amendments	—	—	—	—	—	(25)
Actuarial loss (gain)	53 ¹	(91) ¹	4	(4)	2 ¹	(40) ¹
Benefits paid	(158)	(142)	(10)	(10)	(54)	(58)
Benefit obligation at end of period	\$ 2,123	\$ 2,094	\$ 104	\$ 105	\$ 830	\$ 831
Plan assets at fair value at beginning of period	\$ 2,964	\$ 3,004	\$ —	\$ —	\$ 1,588	\$ 1,559
Actual return on plan assets	371	102	—	—	197	86
Company contribution	—	—	10	10	—	—
Actual benefits paid	(158)	(142)	(10)	(10)	(52)	(57)
Plan assets at fair value at end of period	\$ 3,177	\$ 2,964	\$ —	\$ —	\$ 1,733	\$ 1,588
Funded status	\$ 1,054 ²	\$ 870 ²	\$ (104)	\$ (105)	\$ 903	\$ 757
Consumers						
Benefit obligation at beginning of period			\$ 76	\$ 83	\$ 801	\$ 867
Service cost			—	—	8	11
Interest cost			4	4	42	41
Plan amendments			—	—	—	(24)
Actuarial loss (gain)			3	(4)	1 ¹	(38) ¹
Benefits paid			(7)	(7)	(51)	(56)
Benefit obligation at end of period			\$ 76	\$ 76	\$ 801	\$ 801
Plan assets at fair value at beginning of period			\$ —	\$ —	\$ 1,479	\$ 1,453
Actual return on plan assets			—	—	184	80
Company contribution			7	7	—	—
Actual benefits paid			(7)	(7)	(50)	(54)
Plan assets at fair value at end of period			\$ —	\$ —	\$ 1,613	\$ 1,479
Funded status			\$ (76)	\$ (76)	\$ 812	\$ 678

¹ The actuarial losses for 2025 for the DB Pension Plans and OPEB Plans were primarily the result of lower discount rates. The actuarial gains for 2024 for the DB Pension Plans and OPEB Plan were primarily the result of higher discount rates.

² The total funded status of the DB Pension Plans attributable to Consumers, based on an allocation of expenses, was \$1.0 billion at December 31, 2025 and \$836 million at December 31, 2024.

Presented in the following table is the classification of CMS Energy's and Consumers' retirement benefit plans' assets and liabilities:

	<i>In Millions</i>	
December 31	2025	2024
CMS Energy, including Consumers		
<i>Non-current assets</i>		
DB Pension Plans	\$ 1,054	\$ 870
OPEB Plan	903	757
<i>Current liabilities</i>		
DB SERP	10	10
<i>Non-current liabilities</i>		
DB SERP	94	95
Consumers		
<i>Non-current assets</i>		
DB Pension Plans	\$ 1,009	\$ 836
OPEB Plan	812	678
<i>Current liabilities</i>		
DB SERP	7	7
<i>Non-current liabilities</i>		
DB SERP	69	69

The ABO for the DB Pension Plans was \$1.9 billion at December 31, 2025 and \$1.9 billion at December 31, 2024. At December 31, 2025 and 2024, the PBO and ABO did not exceed plan assets for any of the defined benefit pension plans.

Items Not Yet Recognized as a Component of Net Periodic Benefit Cost: Presented in the following table are the amounts recognized in regulatory assets and AOCI that have not been recognized as components of net periodic benefit cost. For additional details on regulatory assets see Note 3, Regulatory Matters.

In Millions

December 31	DB Pension Plans and DB SERP		OPEB Plan	
	2025	2024	2025	2024
CMS Energy, including Consumers				
<i>Regulatory assets</i>				
Net loss	\$ 548	\$ 653	\$ 93	\$ 176
Prior service cost (credit)	9	12	(61)	(94)
Regulatory assets	\$ 557	\$ 665	\$ 32	\$ 82
<i>AOCI</i>				
Net loss (gain)	57	60	(7)	(3)
Prior service credit	—	—	(2)	(2)
Total amounts recognized in regulatory assets and AOCI	\$ 614	\$ 725	\$ 23	\$ 77
Consumers				
<i>Regulatory assets</i>				
Net loss	\$ 548	\$ 653	\$ 93	\$ 176
Prior service cost (credit)	9	12	(61)	(94)
Regulatory assets	\$ 557	\$ 665	\$ 32	\$ 82
<i>AOCI</i>				
Net loss	18	15	—	—
Total amounts recognized in regulatory assets and AOCI	\$ 575	\$ 680	\$ 32	\$ 82

Plan Assets: Presented in the following tables are the fair values of the assets of CMS Energy's, including Consumers', DB Pension Plans and OPEB Plan, by asset category and by level within the fair value hierarchy. For additional details regarding the fair value hierarchy, see Note 6, Fair Value Measurements.

In Millions

	DB Pension Plans					
	December 31, 2025			December 31, 2024		
	Total	Level 1	Level 2	Total	Level 1	Level 2
Cash and short-term investments	\$ 162	\$ 162	\$ —	\$ 148	\$ 148	\$ —
Mutual funds	—	—	—	—	—	—
	\$ 162	\$ 162	\$ —	\$ 148	\$ 148	\$ —
Pooled funds	3,015			2,816		
Total	\$ 3,177			\$ 2,964		

In Millions

	OPEB Plan					
	December 31, 2025			December 31, 2024		
	Total	Level 1	Level 2	Total	Level 1	Level 2
Cash and short-term investments	\$ 72	\$ 72	\$ —	\$ 35	\$ 35	\$ —
U.S. government and agencies securities	15	—	15	13	—	13
Corporate debt	69	—	69	68	—	68
State and municipal bonds	4	—	4	2	—	2
Foreign bonds	16	—	16	15	—	15
Common stocks	215	215	—	170	170	—
Mutual funds	75	75	—	53	53	—
	\$ 466	\$ 362	\$ 104	\$ 356	\$ 258	\$ 98
Pooled funds	1,267			1,232		
Total	\$ 1,733			\$ 1,588		

Cash and Short-term Investments: Cash and short-term investments consist of money market funds with daily liquidity.

U.S. Government and Agencies Securities: U.S. government and agencies securities consist of U.S. Treasury notes and other debt securities backed by the U.S. government and related agencies. These securities are valued based on quoted market prices.

Corporate Debt: Corporate debt investments consist of investment grade bonds of U.S. issuers from diverse industries. These securities are valued based on quoted market prices, when available, or yields available on comparable securities of issuers with similar credit ratings.

State and Municipal Bonds: State and municipal bonds are valued using a matrix-pricing model that incorporates Level 2 market-based information. The fair value of the bonds is derived from various observable inputs, including benchmark yields, reported securities trades, broker/dealer quotes, bond ratings, and general information on market movements for investment grade state and municipal securities normally considered by market participants when pricing such debt securities.

Foreign Bonds: Foreign corporate and government debt securities are valued based on quoted market prices, when available, or on yields available on comparable securities of issuers with similar credit ratings.

Common Stocks: Common stocks in the OPEB Plan consist of equity securities that are actively managed and tracked to the S&P 500 Index and MSCI All Country World ex-US. These securities are valued at their quoted closing prices.

Mutual Funds: Mutual funds represent shares in registered investment companies that are priced based on the daily quoted net asset values that are publicly available and are the basis for transactions to buy or sell shares in the funds.

Pooled Funds: Pooled funds include both common and collective trust funds as well as special funds that contain only employee benefit plan assets from two or more unrelated benefit plans. These funds primarily consist of U.S. and foreign equity securities, but also include U.S. and foreign fixed-income securities and multi-asset investments. Since these investments are valued at their net asset value as a practical expedient, they are not classified in the fair value hierarchy.

Asset Allocations: Presented in the following table are the investment components of the assets of CMS Energy’s DB Pension Plans and OPEB Plan as of December 31, 2025:

	DB Pension Plans	OPEB Plan
Fixed-income securities	39.2%	37.6%
Equity securities	38.7	42.4
Real asset investments	9.3	8.8
Return-seeking fixed income	7.1	5.6
Liquid alternative investments	4.3	3.7
Cash and cash equivalents	1.4	1.9
	100.0%	100.0%

CMS Energy’s target 2025 asset allocation for the assets of the DB Pension Plans was 40-percent fixed income, 38-percent equity, 11-percent real assets, 7-percent return-seeking fixed income, and 4-percent liquid alternatives.

CMS Energy established union and non-union VEBA trusts to fund future retiree health and life insurance benefits known as OPEB. These trusts are funded through the ratemaking process for Consumers and through direct contributions from the non-utility subsidiaries. CMS Energy’s target 2025 asset allocation for OPEB trusts was 40-percent fixed income, 38-percent equity, 11-percent real assets, 7-percent return-seeking fixed income, and 4-percent liquid alternatives.

The goal of these target allocations was to maximize the long-term return on plan assets, while maintaining a prudent level of risk. The level of acceptable risk is a function of the liabilities of the plans. Equity investments are diversified mostly across the S&P 500 Index, with lesser allocations to the S&P MidCap and SmallCap Indexes and Foreign Equity Funds. Fixed-income investments are diversified across investment grade instruments of government and corporate issuers, as well as high-yield and global bond funds. Return-seeking fixed-income investments are diversified exposure to high-yield bonds, emerging market debt, and bank loans. Real asset investments are diversified across core real estate and real estate investment trusts. Liquid alternatives are investments in private funds comprised of different and independent hedge funds with various investment strategies. CMS Energy uses annual liability measurements, quarterly portfolio reviews, and periodic asset/liability studies to evaluate the need for adjustments to the portfolio allocations.

Contributions: Contributions comprise required amounts and discretionary contributions. Neither CMS Energy nor Consumers made any contributions in 2025 or 2024, or plans to contribute to the DB Pension Plans or OPEB Plan in 2026. Actual future contributions will depend on future investment performance, discount rates, and various factors related to the participants of the DB Pension Plans and OPEB Plan. CMS Energy and Consumers will, at a minimum, contribute to the plans as needed to comply with federal funding requirements.

Benefit Payments: Presented in the following table are the expected benefit payments for each of the next five years and the five-year period thereafter:

	<i>In Millions</i>		
	DB Pension Plans	DB SERP	OPEB Plan
CMS Energy, including Consumers			
2026	\$ 164	\$ 10	\$ 59
2027	165	10	61
2028	164	10	62
2029	164	9	62
2030	164	9	62
2031-2035	801	41	305
Consumers			
2026	\$ 154	\$ 7	\$ 57
2027	155	7	58
2028	154	7	59
2029	155	6	59
2030	154	6	60
2031-2035	756	29	292

Collective Bargaining Agreements: At December 31, 2025, unions represented 44 percent of CMS Energy’s employees and 45 percent of Consumers’ employees. The UWUA represents Consumers’ and NorthStar Clean Energy’s operating, maintenance, construction employees and Consumers’ customer contact center employees. The USW represents Consumers’ Zeeland plant employees. Consumers’ union agreements expire in 2030 and the majority of NorthStar Clean Energy’s represented employees have an agreement that expires in 2029.

12: Stock-based Compensation

CMS Energy and Consumers provide a PISP to officers, employees, and non-employee directors based on their contributions to the successful management of the company. The PISP has a ten-year term, expiring in May 2030.

In 2025, all awards were in the form of restricted stock or restricted stock units. The PISP also allows for unrestricted common stock, stock options, stock appreciation rights, phantom shares, performance units, and incentive options, none of which was granted in 2025, 2024, or 2023.

Shares awarded or subject to stock options, phantom shares, or performance units may not exceed 6.5 million shares from June 2020 through May 2030. CMS Energy and Consumers may issue awards of up to 3,965,601 shares of common stock under the PISP as of December 31, 2025. Shares for which payment or exercise is in cash, as well as shares that expire, terminate, or are canceled or forfeited, may be awarded or granted again under the PISP.

All awards under the PISP vest fully upon death. Upon a change of control of CMS Energy or termination under an officer separation agreement, the awards will vest in accordance with specific officer agreements. If stated in the award, for restricted stock recipients who terminate employment due to retirement or disability, a pro-rata portion of the award will vest upon termination, with any market-based award also contingent upon the outcome of the market condition and any performance-based award contingent upon the outcome of the performance condition. The pro-rata portion is equal to the portion of the service period served between the award grant date and the employee's termination date. The remaining portion of the awards will be forfeited. All awards for directors vest fully upon retirement. Restricted shares may be forfeited if employment terminates for any other reason or if the minimum service requirements are not met, as described in the award document.

Restricted Stock Awards: Restricted stock awards for employees under the PISP are in the form of performance-based, market-based, and time-lapse restricted stock. Award recipients receive shares of CMS Energy common stock that have dividend and voting rights. The dividends on time-lapse restricted stock are paid in cash or in CMS Energy common stock. The dividends on performance-based and market-based restricted stock are paid in restricted shares equal to the value of the dividends. These additional restricted shares are subject to the same vesting conditions as the underlying restricted stock shares.

Performance-based restricted stock vesting is contingent on meeting at least a 36-month service requirement and a performance condition. The performance condition is based on an adjusted measure of CMS Energy's EPS growth relative to a peer group over a three-year period. The awards granted in 2025, 2024, and 2023 require a 38-month service period. Market-based restricted stock vesting is generally contingent on meeting a three-year service requirement and a market condition. The market condition is based on a comparison of CMS Energy's total shareholder return with the median total shareholder return of a peer group over the same three-year period. Depending on the outcome of the performance condition or the market condition, a recipient may earn a total award ranging from zero to 200 percent of the initial grant. Time-lapse restricted stock generally vests after a service period of three years.

Restricted Stock Units: In 2025, 2024, and 2023, CMS Energy and Consumers granted restricted stock units to certain non-employee directors who elected to defer their restricted stock awards. The restricted stock units generally vest after a service period of one year or, if earlier, at the next annual meeting. The restricted stock units will be distributed to the recipients as shares in accordance with the directors' deferral agreements. Restricted stock units do not have voting rights, but do have dividend rights. In lieu of cash dividend payments, the dividends on restricted stock units are paid in additional units equal to the value of the dividends. These additional restricted stock units are subject to the same vesting and

distribution conditions as the underlying restricted stock units. No restricted stock units were forfeited during 2025.

Presented in the following tables is the activity for restricted stock and restricted stock units under the PISP:

Year Ended December 31, 2025	CMS Energy, including Consumers		Consumers	
	Number of Shares	Weighted-average Grant Date Fair Value Per Share	Number of Shares	Weighted-average Grant Date Fair Value Per Share
Nonvested at beginning of period	1,162,787	\$ 59.34	1,081,573	\$ 59.35
<i>Granted</i>				
Restricted stock	523,663	50.19	480,258	49.86
Restricted stock units	18,491	56.80	17,713	56.80
<i>Vested</i>				
Restricted stock	(450,699)	46.30	(424,830)	46.33
Restricted stock units	(27,035)	51.79	(25,994)	51.82
Forfeited – restricted stock	(38,364)	60.19	(36,119)	60.01
Nonvested at end of period	1,188,843	\$ 60.36	1,092,601	\$ 60.36

Year Ended December 31, 2025	CMS Energy, including Consumers	Consumers
<i>Granted</i>		
Time-lapse awards	118,842	109,242
Market-based awards	139,248	126,302
Performance-based awards	147,982	134,540
Restricted stock units	14,406	13,800
Dividends on market-based awards	13,484	12,472
Dividends on performance-based awards	14,458	13,389
Dividends on restricted stock units	4,085	3,913
Additional market-based shares based on achievement of condition	5,982	5,624
Additional performance-based shares based on achievement of condition	83,667	78,689
Total granted	542,154	497,971

CMS Energy and Consumers charge the fair value of the restricted stock awards to expense over the required service period and charge the fair value of the restricted stock units to expense immediately. For performance-based awards, CMS Energy and Consumers estimate the number of shares expected to vest at the end of the performance period based on the probable achievement of the performance objective. Performance-based and market-based restricted stock awards have graded vesting features for retirement-eligible employees, and CMS Energy and Consumers recognize expense for those awards on a graded vesting schedule over the required service period. Expense for performance-based and market-based restricted stock awards for non-retirement-eligible employees and time-lapse awards is recognized on a straight-line basis over the required service period.

The fair value of performance-based and time-lapse restricted stock and restricted stock units is based on the price of CMS Energy's common stock on the grant date. The fair value of market-based restricted stock awards is calculated on the grant date using a Monte Carlo simulation. CMS Energy and Consumers

base expected volatilities on the historical volatility of the price of CMS Energy common stock. The risk-free rate for valuation of the market-based restricted stock awards was based on the three-year U.S. Treasury yield at the award grant date.

Presented in the following table are the most significant assumptions used to estimate the fair value of the market-based restricted stock awards:

Years Ended December 31	2025	2024	2023
Expected volatility	20.7%	20.2%	30.3%
Expected dividend yield	3.1	3.5	2.9
Risk-free rate	4.2	4.1	3.9

Presented in the following table is the weighted-average grant-date fair value of all awards under the PISP:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
<i>Weighted-average grant-date fair value per share</i>			
Restricted stock granted	\$ 50.19	\$ 44.76	\$ 52.62
Restricted stock units granted	56.80	52.43	50.32
Consumers			
<i>Weighted-average grant-date fair value per share</i>			
Restricted stock granted	\$ 49.86	\$ 44.49	\$ 52.42
Restricted stock units granted	56.80	52.46	50.34

Presented in the following table are amounts related to restricted stock awards and restricted stock units:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Fair value of shares that vested during the year	\$ 33	\$ 28	\$ 20
Compensation expense recognized	25	27	28
Income tax benefit recognized	2	3	3
Consumers			
Fair value of shares that vested during the year	\$ 32	\$ 27	\$ 19
Compensation expense recognized	23	25	26
Income tax benefit recognized	2	3	2

At December 31, 2025, \$28 million of total unrecognized compensation cost was related to restricted stock for CMS Energy, including Consumers, and \$26 million of total unrecognized compensation cost was related to restricted stock for Consumers. CMS Energy and Consumers expect to recognize this cost over a weighted-average period of two years.

13: Income Taxes

CMS Energy and its subsidiaries file a consolidated U.S. federal income tax return as well as a Michigan Corporate Income Tax return for the unitary business group and various other state unitary group combined income tax returns. Income taxes are allocated based on each company's separate taxable income in accordance with the CMS Energy tax sharing agreement.

Presented in the following table is the difference between actual income tax expense on continuing operations and income tax expense computed by applying the statutory U.S. federal income tax rate:

Years Ended December 31	<i>In Millions, Except Tax Rate</i>					
	Amount	Percent	Amount	Percent	Amount	Percent
	2025		2024		2023	
CMS Energy, including Consumers						
Income from continuing operations before income taxes	\$ 1,248		\$ 1,123		\$ 954	
Income tax expense at statutory rate	262	21.0 %	236	21.0 %	200	21.0 %
<i>Increase (decrease) in income taxes from:</i>						
State and local income taxes, net of federal income tax effect ¹	77	6.2	58	5.1	40	4.2
<i>Tax credits</i>						
Renewable energy tax credits	(68)	(5.4)	(71)	(6.4)	(55)	(5.8)
Other	(6)	(0.5)	(6)	(0.5)	(7)	(0.7)
Nontaxable or nondeductible items	3	0.2	4	0.4	3	0.3
Changes in unrecognized tax benefits	9	0.7	2	0.2	(11)	(1.2)
<i>Other adjustments</i>						
TCJA excess deferred taxes	(42)	(3.4)	(43)	(3.8)	(40)	(4.2)
Deferred tax adjustment ²	—	—	(16)	(1.4)	—	—
Taxes attributable to noncontrolling interests	15	1.2	12	1.1	17	1.8
Other, net	(4)	(0.3)	—	—	—	—
Income tax expense	\$ 246		\$ 176		\$ 147	
Effective tax rate		19.7 %		15.7 %		15.4 %

In Millions, Except Tax Rate

Years Ended December 31	Amount		Percent		Amount		Percent	
	2025		2024		2023			
Consumers								
Income from continuing operations before income taxes	\$	1,417		\$	1,209		\$	1,028
Income tax expense at statutory rate		298	21.0 %		254	21.0 %		216
<i>Increase (decrease) in income taxes from:</i>								
State and local income taxes, net of federal income tax effect ¹		80	5.7		60	5.0		47
<i>Tax credits</i>								
Renewable energy tax credits		(46)	(3.2)		(51)	(4.2)		(43)
Other		(6)	(0.4)		(6)	(0.5)		(7)
Nontaxable or nondeductible items		3	0.2		3	0.2		3
Changes in unrecognized tax benefits		9	0.6		1	0.1		(12)
<i>Other adjustments</i>								
TCJA excess deferred taxes		(42)	(3.0)		(43)	(3.6)		(40)
Deferred tax adjustment ²		—	—		(16)	(1.3)		—
Other, net		(8)	(0.6)		(2)	(0.2)		(3)
Income tax expense	\$	288		\$	200		\$	161
Effective tax rate			20.3 %			16.5 %		15.7 %

¹ In June 2025, state deferred tax balances were increased by \$12 million to reflect a change in Illinois tax policy that establishes nexus for Consumers. The policy change is effective for tax years beginning January 1, 2026. During 2023, CMS Energy initiated a plan to divest immaterial business activities in a non-Michigan jurisdiction and will no longer have a taxable presence within that jurisdiction. As a result of these actions, CMS Energy reversed a \$13 million non-Michigan reserve, all of which was recognized at Consumers.

² During 2024, Consumers recognized a \$16 million tax benefit resulting from the expiration of the statute of limitations associated with audit points for the 2018 and 2019 tax years.

State Income Tax Claim: In February 2025, CMS Energy received an adverse ruling from the Michigan Tax Tribunal in regards to the methodology of state apportionment for Consumers' electricity sales to MISO. In March 2025, CMS Energy filed an appeal with the Michigan Court of Appeals and a hearing was held in February 2026. CMS Energy and Consumers have evaluated and concluded their uncertain tax positions associated with this matter to be sufficient as of December 31, 2025. While CMS Energy and Consumers expect the appeal to prevail, if it were to fail, the companies would be required to revise the estimated value of their state deferred tax liabilities, which could result in a material impact to their results of operations.

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent

bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

Renewable Energy Tax Credits: Under the Inflation Reduction Act of 2022, renewable energy tax credits produced after 2022 are eligible to be transferred to third parties. These sales are accounted for under ASC 740 with the discount from the sale of the tax credits included as a component of income tax expense. Renewable energy tax credits that have been generated and sold are presented as accounts receivable on CMS Energy's and Consumers' consolidated balance sheets until proceeds from the sale are received. Proceeds from the sale of tax credits are presented as operating activities on their consolidated statements of cash flows, consistent with the presentation of cash taxes paid.

During 2025, CMS Energy sold renewable energy tax credits generated in 2025 and received proceeds of \$36 million, all of which was recognized at Consumers. CMS Energy also received proceeds of \$13 million during 2025 from the 2024 sale of renewable energy tax credits, all of which was recognized at Consumers. CMS Energy will receive an additional \$32 million in 2026 from the renewable energy tax credits generated and sold in 2025, of which \$10 million will be recognized at Consumers.

Presented in the following table are the significant components of income tax expense on continuing operations:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
<i>Current income taxes</i>			
Federal	\$ 34	\$ 34	\$ 5
State and local	9	—	1
	<u>\$ 43</u>	<u>\$ 34</u>	<u>\$ 6</u>
<i>Deferred income taxes</i>			
Federal	107	70	107
State and local	100	76	38
	<u>\$ 207</u>	<u>\$ 146</u>	<u>\$ 145</u>
Deferred income tax credit	(4)	(4)	(4)
Tax expense	<u>\$ 246</u>	<u>\$ 176</u>	<u>\$ 147</u>
Consumers			
<i>Current income taxes</i>			
Federal	\$ 207	\$ 78	\$ 3
State and local	33	7	2
	<u>\$ 240</u>	<u>\$ 85</u>	<u>\$ 5</u>
<i>Deferred income taxes</i>			
Federal	(27)	51	117
State and local	79	68	43
	<u>\$ 52</u>	<u>\$ 119</u>	<u>\$ 160</u>
Deferred income tax credit	(4)	(4)	(4)
Tax expense	<u>\$ 288</u>	<u>\$ 200</u>	<u>\$ 161</u>

Presented in the following table are income taxes paid:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Federal	\$ 28	\$ 27	\$ 15
State	1	1	—
Total	\$ 29	\$ 28	\$ 15
Consumers			
Federal	\$ 189	\$ 57	\$ 23
State	21	—	8
Total	\$ 210	\$ 57	\$ 31

CMS Energy and Consumers are domiciled in the U.S. and are not subject to taxes in any foreign jurisdiction. State income taxes paid (net of refunds) are primarily attributable to the state of Michigan.

Presented in the following table are the principal components of deferred income tax assets (liabilities) recognized:

	<i>In Millions</i>	
December 31	2025	2024
CMS Energy, including Consumers		
<i>Deferred income tax assets</i>		
Net regulatory tax liability	\$ 294	\$ 307
Tax loss and credit carryforwards	139	258
Reserves and accruals	16	27
Total deferred income tax assets	\$ 449	\$ 592
Valuation allowance	(2)	(1)
Total deferred income tax assets, net of valuation allowance	\$ 447	\$ 591
<i>Deferred income tax liabilities</i>		
Plant, property, and equipment	\$ (2,833)	\$ (2,682)
Employee benefits	(558)	(507)
Gas inventory	(24)	(38)
Securitized costs	(137)	(167)
Other	(147)	(122)
Total deferred income tax liabilities	\$ (3,699)	\$ (3,516)
Total net deferred income tax liabilities	\$ (3,252)	\$ (2,925)
Consumers		
<i>Deferred income tax assets</i>		
Net regulatory tax liability	\$ 294	\$ 307
Tax loss and credit carryforwards	18	37
Reserves and accruals	13	24
Total deferred income tax assets	\$ 325	\$ 368
<i>Deferred income tax liabilities</i>		
Plant, property, and equipment	\$ (2,808)	\$ (2,658)
Employee benefits	(534)	(489)
Gas inventory	(24)	(38)
Securitized costs	(137)	(167)
Other	(23)	(69)
Total deferred income tax liabilities	\$ (3,526)	\$ (3,421)
Total net deferred income tax liabilities	\$ (3,201)	\$ (3,053)

Deferred tax assets and liabilities are recognized for the estimated future tax effect of temporary differences between the tax basis of assets or liabilities and the reported amounts on CMS Energy's and Consumers' consolidated financial statements.

Presented in the following table are the tax loss and credit carryforwards at December 31, 2025:

	<i>In Millions</i>	
	Tax Attribute	Expiration
CMS Energy, including Consumers		
Michigan net operating loss carryforwards	\$ 15	2030 – 2033
Arkansas net operating loss carryforwards	2	2033 - 2035
Local net operating loss carryforwards	2	2025 – 2040
General business credits ¹	120	2038 – 2045
Total tax attributes	\$ 139	
Consumers		
Michigan net operating loss carryforwards	\$ 10	2030 – 2033
General business credits ¹	8	2038 – 2045
Total tax attributes	\$ 18	

¹ General business credits comprise research and development tax credits and renewable energy tax credits that are not expected to be transferred to third parties.

CMS Energy has provided a valuation allowance of \$2 million for state and local tax loss carryforwards. CMS Energy and Consumers expect to utilize fully their tax loss and credit carryforwards for which no valuation allowance has been provided. It is reasonably possible that further adjustments will be made to the valuation allowances within one year.

Presented in the following table is a reconciliation of the beginning and ending amount of uncertain tax benefits:

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Balance at beginning of period	\$ 24	\$ 26	\$ 28
Additions for current-year tax positions	2	1	1
Additions for prior-year tax positions	7	2	—
Reductions for lapse of statute of limitations	(4)	(5)	(3)
Balance at end of period	\$ 29	\$ 24	\$ 26
Consumers			
Balance at beginning of period	\$ 32	\$ 36	\$ 36
Additions for current-year tax positions	1	6	1
Additions for prior-year tax positions	7	1	2
Reductions for lapse of statute of limitations	(4)	(11)	(3)
Balance at end of period	\$ 36	\$ 32	\$ 36

If recognized, all of these uncertain tax benefits would affect CMS Energy's and Consumers' annual effective tax rates in future years. One uncertain tax benefit relates to the methodology of state apportionment for Consumers' electricity sales to MISO. CMS Energy has filed an appeal on an adverse ruling received from the Michigan Tax Tribunal on this methodology and a hearing was held in February 2026.

CMS Energy and Consumers recognize accrued interest and penalties, where applicable, as part of income tax expense. CMS Energy, including Consumers, recognized immaterial interest and penalties for each of the years ended December 31, 2025, 2024, and 2023.

The amount of income taxes paid is subject to ongoing audits by federal, state, local, and foreign tax authorities, which can result in proposed assessments. CMS Energy's federal income tax returns for 2022 and subsequent years remain subject to examination by the IRS. CMS Energy's Michigan Corporate Income Tax returns for 2013 through 2016 and 2021 and subsequent years remain subject to examination by the State of Michigan. CMS Energy's and Consumers' estimate of the potential outcome for any uncertain tax issue is highly judgmental. CMS Energy and Consumers believe that their accrued tax liabilities at December 31, 2025 were adequate for all years.

14: Earnings Per Share—CMS Energy

Presented in the following table are CMS Energy's basic and diluted EPS computations based on income from continuing operations:

	<i>In Millions, Except Per Share Amounts</i>		
Years Ended December 31	2025	2024	2023
<i>Income available to common stockholders</i>			
Income from continuing operations	\$ 1,002	\$ 947	\$ 807
Less loss attributable to noncontrolling interests	(69)	(56)	(79)
Less preferred stock dividends	10	10	10
Income from continuing operations available to common stockholders – basic and diluted	\$ 1,061	\$ 993	\$ 876
<i>Average common shares outstanding</i>			
Weighted-average shares – basic	300.4	297.6	291.2
Add dilutive nonvested stock awards	0.5	0.7	0.5
Add dilutive forward equity sale contracts	0.1	—	—
Weighted-average shares – diluted	301.0	298.3	291.7
<i>Income from continuing operations per average common share available to common stockholders</i>			
Basic	\$ 3.53	\$ 3.34	\$ 3.01
Diluted	3.53	3.33	3.01

Nonvested Stock Awards

CMS Energy's nonvested stock awards are composed of participating and non-participating securities. The participating securities accrue cash dividends when common stockholders receive dividends. Since the recipient is not required to return the dividends to CMS Energy if the recipient forfeits the award, the nonvested stock awards are considered participating securities. As such, the participating nonvested stock awards were included in the computation of basic EPS. The non-participating securities accrue stock dividends that vest concurrently with the stock award. If the recipient forfeits the award, the stock dividends accrued on the non-participating securities are also forfeited. Accordingly, the non-participating awards and stock dividends were included in the computation of diluted EPS, but not in the computation of basic EPS.

Forward Equity Sale Contracts

CMS Energy has entered into forward equity sale contracts. These forward equity sale contracts are non-participating securities. While the forward sale price in the forward equity sale contract is decreased on certain dates by certain predetermined amounts to reflect expected dividend payments, these price adjustments were set upon inception of the agreement and the forward contract does not give the owner the right to participate in undistributed earnings. Accordingly, the forward equity sale contracts were included in the computation of diluted EPS, but not in the computation of basic EPS.

The potentially dilutive impact from these forward equity sale contracts is reflected in diluted EPS using the treasury stock method. There will be a dilutive effect on EPS when the average market price of common stock shares is above the applicable adjusted forward sale price. Additionally, any physical settlement or net share settlement of the agreements would dilute EPS. For further details on the forward equity sale contracts, see Note 5, Financings and Capitalization.

Convertible Securities

CMS Energy has issued convertible senior notes. Potentially dilutive common shares issuable upon conversion of the convertible senior notes are determined using the if-converted method for calculating diluted EPS. Upon conversion, the convertible senior notes are required to be paid in cash with only amounts exceeding the principal permitted to be settled in shares. Accordingly, the convertible senior notes were included in the computation of diluted EPS, but not in the computation of basic EPS. The impact to diluted EPS was de minimis.

15: Revenue

Presented in the following tables are the components of operating revenue:

In Millions

Year Ended December 31, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 5,578	\$ 2,468	\$ —	\$ 8,046
Other	—	—	259	259
Revenue recognized from contracts with customers	\$ 5,578	\$ 2,468	\$ 259	\$ 8,305
Leasing income	—	—	149	149
Financing income	10	6	—	16
Consumers alternative-revenue programs	50	19	—	69
Total operating revenue – CMS Energy	\$ 5,638	\$ 2,493	\$ 408	\$ 8,539
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 2,661	\$ 1,701		\$ 4,362
Commercial	1,888	538		2,426
Industrial	762	62		824
Other	267	167		434
Revenue recognized from contracts with customers	\$ 5,578	\$ 2,468		\$ 8,046
Financing income	10	6		16
Alternative-revenue programs	50	19		69
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	\$ 5,638	\$ 2,493		\$ 8,132

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 4,995	\$ 2,114	\$ —	\$ 7,109
Other	—	—	211	211
Revenue recognized from contracts with customers	\$ 4,995	\$ 2,114	\$ 211	\$ 7,320
Leasing income	—	—	105	105
Financing income	10	5	—	15
Consumers alternative-revenue programs	56	19	—	75
Total operating revenue – CMS Energy	\$ 5,061	\$ 2,138	\$ 316	\$ 7,515
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 2,318	\$ 1,429		\$ 3,747
Commercial	1,674	440		2,114
Industrial	670	50		720
Other	333	195		528
Revenue recognized from contracts with customers	\$ 4,995	\$ 2,114		\$ 7,109
Financing income	10	5		15
Alternative-revenue programs	56	19		75
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	\$ 5,061	\$ 2,138		\$ 7,200

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 4,686	\$ 2,394	\$ —	\$ 7,080
Other	—	—	181	181
Revenue recognized from contracts with customers	\$ 4,686	\$ 2,394	\$ 181	\$ 7,261
Leasing income	—	—	116	116
Financing income	10	6	—	16
Consumers alternative-revenue programs	49	20	—	69
Total operating revenue – CMS Energy	\$ 4,745	\$ 2,420	\$ 297	\$ 7,462
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 2,236	\$ 1,619		\$ 3,855
Commercial	1,550	489		2,039
Industrial	660	60		720
Other	240	226		466
Revenue recognized from contracts with customers	\$ 4,686	\$ 2,394		\$ 7,080
Financing income	10	6		16
Alternative-revenue programs	49	20		69
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	\$ 4,745	\$ 2,420		\$ 7,166

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities.

Electric and Gas Utilities

Consumers Utility Revenue: Consumers recognizes revenue primarily from the sale of electric and gas utility services at tariff-based rates regulated by the MPSC. Consumers' customer base consists of a mix of residential, commercial, and diversified industrial customers. Consumers' tariff-based sales performance obligations are described below.

- Consumers has performance obligations for the service of standing ready to deliver electricity or natural gas to customers, and it satisfies these performance obligations over time. Consumers recognizes revenue at a fixed rate as it provides these services. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of Consumers' service to stand ready to deliver.
- Consumers has performance obligations for the service of delivering the commodity of electricity or natural gas to customers, and it satisfies these performance obligations upon delivery. Consumers recognizes revenue at a price per unit of electricity or natural gas delivered, based on the tariffs established by the MPSC. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of a bundled product comprising the commodity, electricity or natural gas, and the service of delivering such commodity.

In some instances, Consumers has specific fixed-term contracts with large commercial and industrial customers to provide electricity or gas at certain tariff rates or to provide gas transportation services at contracted rates. The amount of electricity and gas to be delivered under these contracts and the associated future revenue to be received are generally dependent on the customers' needs. Accordingly, Consumers recognizes revenues at the tariff or contracted rate as electricity or gas is delivered to the customer. Consumers also has other miscellaneous contracts with customers related to pole and other property rentals and utility contract work. Generally, these contracts are short term or evergreen in nature.

Accounts Receivable and Unbilled Revenues: Accounts receivable comprise trade receivables and unbilled receivables. CMS Energy and Consumers record their accounts receivable at cost less an allowance for uncollectible accounts. The allowance is increased for uncollectible accounts expense and decreased for account write-offs net of recoveries. CMS Energy and Consumers establish the allowance based on historical losses, management's assessment of existing economic conditions, customer payment trends, and reasonable and supported forecast information. CMS Energy and Consumers assess late payment fees on trade receivables based on contractual past-due terms established with customers. Accounts are written off when deemed uncollectible, which is generally when they become six months past due.

CMS Energy and Consumers recorded uncollectible accounts expense of \$40 million for the year ended December 31, 2025, \$33 million for the year ended December 31, 2024, and \$34 million for the year ended December 31, 2023.

Consumers' customers are billed monthly in cycles having billing dates that do not generally coincide with the end of a calendar month. This results in customers having received electricity or natural gas that they have not been billed for as of the month-end. Consumers estimates its unbilled revenues by applying an average billed rate to total unbilled deliveries for each customer class. Unbilled revenues, which are recorded as accounts receivable and accrued revenue on CMS Energy's and Consumers' consolidated balance sheets, were \$659 million at December 31, 2025 and \$584 million at December 31, 2024.

Alternative-revenue Programs: Consumers accounts for its energy waste reduction incentive mechanism, financial compensation mechanism, and demand response incentive mechanism as alternative-revenue programs.

Consumers recognizes revenue related to the energy waste reduction incentive as soon as energy savings exceed the annual targets established by the MPSC. Revenue related to the financial compensation mechanism is recognized as payments are made on MPSC-approved PPAs. Under a demand response incentive mechanism, Consumers earns a financial incentive when it meets demand response targets set by the MPSC. Consumers recognizes revenue related to this program once demand response incentive objectives are complete, the incentive amount is calculable, and the incentive revenue will be collected within a 24-month period. For additional information on these mechanisms, see Note 3, Regulatory Matters.

Consumers does not reclassify revenue from its alternative-revenue program to revenue from contracts with customers at the time the amounts are collected from customers.

16: Other Income and Other Expense

Presented in the following table are the components of other income and other expense at CMS Energy and Consumers:

Years Ended December 31	<i>In Millions</i>		
	2025	2024	2023
CMS Energy, including Consumers			
<i>Other income</i>			
Gain on extinguishment of debt ¹	\$ 72	\$ 110	\$ 131
Interest income	37	50	37
Interest income – related parties	1	—	—
Allowance for equity funds used during construction	23	29	7
Income from equity method investees	5	7	7
All other	13	11	13
Total other income – CMS Energy	\$ 151	\$ 207	\$ 195
Consumers			
<i>Other income</i>			
Interest income	\$ 22	\$ 42	\$ 25
Interest income – related parties	4	5	5
Allowance for equity funds used during construction	23	29	7
All other	6	9	12
Total other income – Consumers	\$ 55	\$ 85	\$ 49
CMS Energy, including Consumers			
<i>Other expense</i>			
Donations	\$ (10)	\$ (18)	\$ (1)
Civic and political expenditures	(7)	(5)	(5)
All other	(10)	(9)	(7)
Total other expense – CMS Energy	\$ (27)	\$ (32)	\$ (13)
Consumers			
<i>Other expense</i>			
Donations	\$ (10)	\$ (18)	\$ (1)
Civic and political expenditures	(5)	(5)	(5)
All other	(7)	(7)	(6)
Total other expense – Consumers	\$ (22)	\$ (30)	\$ (12)

¹ For information regarding the gain on extinguishment of debt, see Note 5, Financings and Capitalization—CMS Energy's Purchase of Consumers' First Mortgage Bonds.

17: Reportable Segments

Reportable segments consist of business units defined by the products and services they offer. CMS Energy's and Consumers' chief operating decision-maker is the CEO. The chief operating decision-maker evaluates segment performance and profitability using net income available to CMS Energy's common stockholders. This metric provides a clear, consistent basis for analyzing the financial results of each segment and supports decision-making regarding the allocation of resources.

Resource allocation to CMS Energy's and Consumers' segments begins with the annual budgeting process, which establishes initial funding and resource levels for each segment. The budget incorporates key financial and operational inputs, including anticipated revenues, expenses, and capital requirements, aligning with CMS Energy's and Consumers' strategic objectives and regulatory obligations. The chief operating decision-maker reviews budget-to-actual variances on a monthly basis and makes interim decisions to reallocate resources among segments as needed, ensuring a timely and effective response to changing conditions. For the electric utility and gas utility segments, the chief operating decision-maker uses this assessment to determine whether the segments are achieving their regulatory authorized return on equity.

Accounting policies for CMS Energy's and Consumers' segments are as described in Note 1, Significant Accounting Policies. The consolidated financial statements reflect the assets, liabilities, revenues, and expenses of the individual segments when appropriate. Accounts are allocated among the segments when common accounts are attributable to more than one segment. The allocations are based on certain measures of business activities, such as revenue, labor dollars, customers, other operating and maintenance expense, construction expense, leased property, taxes, or functional surveys. For example, customer receivables are allocated based on revenue, and pension provisions are allocated based on labor dollars.

Inter-segment sales and transfers are accounted for at current market prices and are eliminated in consolidated net income available to common stockholders by segment. Inter-segment sales and transfers were immaterial for all periods presented.

CMS Energy

The segments reported for CMS Energy are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan
- NorthStar Clean Energy, consisting of various subsidiaries engaging in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production

CMS Energy presents corporate interest and other expenses, discontinued operations, and Consumers' other consolidated entities within other reconciling items.

Consumers

The segments reported for Consumers are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan

Consumers' other consolidated entities are presented within other reconciling items.

Presented in the following tables is financial information by segment:

<i>In Millions</i>						
Year Ended December 31, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	\$ 5,638	\$ 2,493	\$ 408	\$ 8,539	\$ —	\$ 8,539
<i>Operating expenses</i>						
Power supply cost ¹	2,193	—	264	2,457	—	2,457
Cost of gas sold	—	803	6	809	—	809
Maintenance and other operating expenses	1,146	468	100	1,714	13	1,727
Depreciation and amortization	903	350	52	1,305	1	1,306
General taxes	297	201	14	512	1	513
Total operating expenses	4,539	1,822	436	6,797	15	6,812
Operating Income (Loss)	1,099	671	(28)	1,742	(15)	1,727
Other income ²	124	83	17	224	86	310
Interest charges	353	206	(7)	552	237	789
Income (Loss) Before Income Taxes	870	548	(4)	1,414	(166)	1,248
Income tax expense (benefit)	150	138	(4)	284	(38)	246
Income (Loss) From Continuing Operations	720	410	—	1,130	(128)	1,002
Other segment items ³	(1)	(1)	71	69	(10)	59
Net Income (Loss) Available to Common Stockholders	\$ 719	\$ 409	\$ 71	\$ 1,199	\$ (138)	\$ 1,061
Property, plant, and equipment, gross	\$ 21,871 ⁴	\$ 14,218 ⁴	\$ 1,649	\$ 37,738	\$ 25	\$ 37,763
Investments in equity method investees	—	—	61	61	—	61
Total assets	22,760 ⁴	14,188 ⁴	2,496	39,444	497	39,941
Capital expenditures⁵	2,408 ⁶	1,064 ⁶	498	3,970	—	3,970

¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Includes income from equity method investees of \$5 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense

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- ³ Other segment items comprise loss attributable to noncontrolling interests and preferred stock dividends.
- ⁴ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.
- ⁵ Amounts include assets placed under finance lease.
- ⁶ Amounts include a portion of Consumers' capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	\$ 5,638	\$ 2,493	\$ 8,131	\$ 1	\$ 8,132
<i>Operating expenses</i>					
Power supply cost ¹	2,193	—	2,193	—	2,193
Cost of gas sold	—	803	803	—	803
Maintenance and other operating expenses	1,146	468	1,614	—	1,614
Depreciation and amortization	903	350	1,253	1	1,254
General taxes	297	201	498	1	499
Total operating expenses	4,539	1,822	6,361	2	6,363
Operating Income (Loss)	1,099	671	1,770	(1)	1,769
Other income	124	83	207	1	208
Interest charges	353	206	559	1	560
Income (Loss) Before Income Taxes	870	548	1,418	(1)	1,417
Income tax expense	150	138	288	—	288
Net Income (Loss)	720	410	1,130	(1)	1,129
Other segment items ²	(1)	(1)	(2)	—	(2)
Net Income (Loss) Available to Common Stockholder	\$ 719	\$ 409	\$ 1,128	\$ (1)	\$ 1,127
Property, plant, and equipment, gross	\$ 21,871 ³	\$ 14,218 ³	\$ 36,089	\$ 31	\$ 36,120
Total assets	22,814 ³	14,229 ³	37,043	48	37,091
Capital expenditures ⁴	2,408 ⁵	1,064 ⁵	3,472	—	3,472

- ¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.
- ² Other segment items comprise preferred stock dividends.
- ³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.
- ⁴ Amounts include assets placed under finance lease.
- ⁵ Amounts include a portion of Consumers' capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	\$ 5,061	\$ 2,138	\$ 316	\$ 7,515	\$ —	\$ 7,515
<i>Operating expenses</i>						
Power supply cost ¹	1,867	—	161	2,028	—	2,028
Cost of gas sold	—	637	3	640	—	640
Maintenance and other operating expenses	1,066	454	101	1,621	17	1,638
Depreciation and amortization	865	325	49	1,239	1	1,240
General taxes	281	188	12	481	1	482
Total operating expenses	4,079	1,604	326	6,009	19	6,028
Operating Income (Loss)	982	534	(10)	1,506	(19)	1,487
Other income ²	126	86	14	226	118	344
Interest charges	324	192	4	520	188	708
Income (Loss) Before Income Taxes	784	428	—	1,212	(89)	1,123
Income tax expense (benefit)	102	99	(5)	196	(20)	176
Income (Loss) From Continuing Operations	682	329	5	1,016	(69)	947
Other segment items ³	(1)	(1)	58	56	(10)	46
Net Income (Loss) Available to Common Stockholders	\$ 681	\$ 328	\$ 63	\$ 1,072	\$ (79)	\$ 993
Property, plant, and equipment, gross	\$ 20,137 ⁴	\$ 13,268 ⁴	\$ 1,506	\$ 34,911	\$ 21	\$ 34,932
Investments in equity method investees	—	—	64	64	—	64
Total assets	20,710 ⁴	13,247 ⁴	1,893	35,850	70	35,920
Capital expenditures ⁵	1,871 ⁶	1,141 ⁶	288	\$ 3,300	1	3,301

¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Includes income from equity method investees of \$7 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense.

³ Other segment items comprise loss attributable to noncontrolling interests and preferred stock dividends.

⁴ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

⁵ Amounts include assets placed under finance lease.

⁶ Amounts include a portion of Consumers' capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	\$ 5,061	\$ 2,138	\$ 7,199	\$ 1	\$ 7,200
<i>Operating expenses</i>					
Power supply cost ¹	1,867	—	1,867	—	1,867
Cost of gas sold	—	637	637	—	637
Maintenance and other operating expenses	1,066	454	1,520	—	1,520
Depreciation and amortization	865	325	1,190	1	1,191
General taxes	281	188	469	1	470
Total operating expenses	4,079	1,604	5,683	2	5,685
Operating Income (Loss)	982	534	1,516	(1)	1,515
Other income	126	86	212	—	212
Interest charges	324	192	516	2	518
Income (Loss) Before Income Taxes	784	428	1,212	(3)	1,209
Income tax expense (benefit)	102	99	201	(1)	200
Net Income (Loss)	682	329	1,011	(2)	1,009
Other segment items ²	(1)	(1)	(2)	—	(2)
Net Income (Loss) Available to Common Stockholder	\$ 681	\$ 328	\$ 1,009	\$ (2)	\$ 1,007
Property, plant, and equipment, gross	\$ 20,137 ³	\$ 13,268 ³	\$ 33,405	\$ 29	\$ 33,434
Total assets	20,767 ³	13,289 ³	34,056	32	34,088
Capital expenditures ⁴	1,871 ⁵	1,141 ⁵	3,012	—	3,012

¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise preferred stock dividends.

³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

⁴ Amounts include assets placed under finance lease.

⁵ Amounts include a portion of Consumers' capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	\$ 4,745	\$ 2,420	\$ 297	\$ 7,462	\$ —	\$ 7,462
<i>Operating expenses</i>						
Power supply cost ¹	1,841	—	170	2,011	—	2,011
Cost of gas sold	—	897	5	902	—	902
Maintenance and other operating expenses	1,075	511	88	1,674	13	1,687
Depreciation and amortization	797	338	43	1,178	2	1,180
General taxes	260	176	10	446	1	447
Total operating expenses	3,973	1,922	316	6,211	16	6,227
Operating Income (Loss)	772	498	(19)	1,251	(16)	1,235
Other income ²	131	77	12	220	142	362
Interest charges	285	161	2	448	195	643
Income (Loss) Before Income Taxes	618	414	(9)	1,023	(69)	954
Income tax expense (benefit)	67	98	4	169	(22)	147
Income (Loss) From Continuing Operations	551	316	(13)	854	(47)	807
Other segment items ³	(1)	(1)	80	78	(8)	70
Net Income (Loss) Available to Common Stockholders	\$ 550	\$ 315	\$ 67	\$ 932	\$ (55)	\$ 877

¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Includes income from equity method investees of \$7 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense.

³ Other segment items comprise income from discontinued operations, net of tax, loss attributable to noncontrolling interests, and preferred stock dividends.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	\$ 4,745	\$ 2,420	\$ 7,165	\$ 1	\$ 7,166
<i>Operating expenses</i>					
Power supply cost ¹	1,841	—	1,841	—	1,841
Cost of gas sold	—	897	897	—	897
Maintenance and other operating expenses	1,075	511	1,586	—	1,586
Depreciation and amortization	797	338	1,135	2	1,137
General taxes	260	176	436	1	437
Total operating expenses	3,973	1,922	5,895	3	5,898
Operating Income (Loss)	772	498	1,270	(2)	1,268
Other income	131	77	208	—	208
Interest charges	285	161	446	2	448
Income (Loss) Before Income Taxes	618	414	1,032	(4)	1,028
Income tax expense (benefit)	67	98	165	(4)	161
Net Income	551	316	867	—	867
Other segment items ²	(1)	(1)	(2)	—	(2)
Net Income Available to Common Stockholder	\$ 550	\$ 315	\$ 865	\$ —	\$ 865

¹ Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise preferred stock dividends.

18: Related-party Transactions—Consumers

Consumers enters into a number of transactions with related parties in the normal course of business. These transactions include but are not limited to:

- purchases of electricity from affiliates of NorthStar Clean Energy
- payments to and from CMS Energy related to parent company overhead costs
- payments of principal and interest when due to CMS Energy related to borrowings under certain credit agreements and CMS Energy's repurchase of Consumers' first mortgage bonds

Transactions involving power supply purchases from certain affiliates of NorthStar Clean Energy are based on state law and competitive bidding. The payment of parent company overhead costs is based on the use of accepted industry allocation methodologies. These payments are for costs that occur in the normal course of business. Purchases of power and capacity from affiliates of NorthStar Clean Energy totaled \$94 million in 2025, \$71 million in 2024, and \$75 million in 2023.

Amounts payable to related parties for purchased power and other services were \$19 million at December 31, 2025 and \$20 million at December 31, 2024. Accounts receivable from related parties were \$13 million at December 31, 2025 and \$15 million at December 31, 2024.

CMS Energy has a demand note payable to the DB SERP rabbi trust. The demand note bears interest at an annual rate of 4.10 percent and has a maturity date of 2028. The portion of the demand note attributable to Consumers was recorded as a note receivable – related party on Consumers' consolidated balance sheets at December 31, 2025 and 2024. For more information about Consumers' note receivable – related party, see Note 7, Financial Instruments.

Consumers has a natural gas transportation agreement with a subsidiary of CMS Energy that extends through 2038, related to a pipeline owned by Consumers. For additional details about the agreement, see Note 9, Leases.

CMS Energy has repurchased certain of Consumers' first mortgage bonds. Interest payable to related parties was \$9 million at December 31, 2025 and \$7 million at December 31, 2024. For more information about these repurchases, see Note 5, Financings and Capitalization—CMS Energy's Purchase of Consumers' First Mortgage Bonds.

In December 2025, Consumers renewed a short-term credit agreement with CMS Energy, permitting Consumers to borrow up to \$500 million. For additional details about the agreement, see Note 5, Financings and Capitalization—Short-term Borrowings.

19: Variable Interest Entities

Consolidated VIEs: In March 2025, NorthStar Clean Energy sold a 50-percent interest in NWO Wind Equity Holdings for net proceeds of \$36 million. NWO Wind Equity Holdings holds the Class B membership interest in NWO Holdco, the holding company of a 100-MW wind project located in Paulding County, Ohio. Additionally in March 2025, NorthStar Clean Energy sold a 50-percent interest in Delta Solar Equity Holdings for net proceeds of \$8 million. Delta Solar Equity Holdings is the holding company of a 24-MW solar project located in Delta Township, Michigan.

In December 2025, NorthStar Clean Energy sold a Class A membership interest in BG Solar Holdings to a tax equity investor. BG Solar Holdings is the holding company of a 200-MW solar generation project being constructed in Branch County, Michigan. All of the project’s nameplate capacity has been committed under a 15-year renewable energy purchase agreement. The tax equity investor contributed \$15 million and recognized a deemed contribution of \$35 million associated with BG Solar Holdings’ sale of investment tax credits related to a portion of the project placed into service for tax purposes in 2025. The tax equity investor will contribute additional amounts upon commercial operation of the project in 2026.

NorthStar Clean Energy consolidates these and other entities that it does not wholly own, but for which it manages and controls the entities’ operating activities. NorthStar Clean Energy is the primary beneficiary of these entities because it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive benefits from the companies. Presented in the following table is information about the VIEs NorthStar Clean Energy consolidates:

Consolidated VIE	NorthStar Clean Energy’s ownership interest	Description of VIE
Aviator Wind Equity Holdings	51-percent ownership interest ¹	Holds a Class B membership interest in Aviator Wind
Aviator Wind	Class B membership interest ²	Holding company of a 525-MW wind generation project in Coke County, Texas
BG Solar Holdings	Class B membership interest ²	Holding company of a 200-MW solar generation project in Branch County, Michigan
Delta Solar Equity Holdings	50-percent ownership interest ¹	Holding company of a 24-MW solar generation project in Delta Township, Michigan
Newport Solar Holdings	Class B membership interest ²	Holding company of a 180-MW solar generation project in Jackson County, Arkansas
NWO Wind Equity Holdings	50-percent ownership interest ¹	Holds a Class B membership interest in NWO Holdco
NWO Holdco	Class B membership interest ²	Holding company of a 100-MW wind generation project in Paulding County, Ohio

¹ The remaining ownership interest is presented as noncontrolling interest on CMS Energy’s consolidated balance sheets.

² The Class A membership interest in the entity is held by a tax equity investor and is presented as noncontrolling interest on CMS Energy’s consolidated balance sheets. Under the associated limited liability company agreement, the tax equity investor is guaranteed preferred returns from the entity.

Earnings, tax attributes, and cash flows generated by the entities in which NorthStar Clean Energy holds a Class B membership are allocated among and distributed to the membership classes in accordance with

the ratios specified in the associated limited liability company agreements; these ratios change over time and are not representative of the ownership interest percentages of each membership class. Since these entities' income and cash flows are not distributed among their investors based on ownership interest percentages, NorthStar Clean Energy allocates the entities' income (loss) among the investors by applying the hypothetical liquidation at book value method. This method calculates each investor's earnings based on a hypothetical liquidation of the entities at the net book value of underlying assets as of the balance sheet date. The liquidation tax gain (loss) is allocated to each investor's capital account, resulting in income (loss) equal to the period change in the investor's capital account balance.

Presented in the following table are the carrying values of the VIEs' assets and liabilities included on CMS Energy's consolidated balance sheets:

	<i>In Millions</i>	
December 31	2025	2024
<i>Current</i>		
Cash and cash equivalents	\$ 20	\$ 18
Restricted cash	19	—
Accounts receivable	42	4
Prepayments and other current assets	5	3
<i>Non-current</i>		
Plant, property, and equipment, net	1,037	1,024
Construction work in progress	357	—
Other non-current assets	5	3
Total assets¹	\$ 1,485	\$ 1,052
<i>Current</i>		
Current portion of long-term debt and finance leases	\$ 65	\$ —
Accounts payable	29	8
<i>Non-current</i>		
Long-term debt	118	—
Non-current portion of finance leases	39	23
AROs	38	33
Other non-current liabilities	3	—
Total liabilities	\$ 292	\$ 64

¹ Assets may be used only to meet VIEs' obligations and commitments.

NorthStar Clean Energy is obligated under certain indemnities that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. For additional details on these indemnity obligations, see Note 4, Contingencies and Commitments—Guarantees.

Consumers' wholly-owned subsidiaries, Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding, are VIEs designed to collateralize Consumers' securitization bonds. These entities are considered VIEs primarily because their equity capitalization is insufficient to support their operations. Consumers is the primary beneficiary of and consolidates these VIEs, as it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive benefits from the companies. The VIEs' primary assets and liabilities comprise non-current regulatory assets and long-term debt. For more information on

these assets and liabilities, see Note 3, Regulatory Matters—Securitized Costs and Note 5, Financings and Capitalization—Securitization Bonds

Non-consolidated VIEs: NorthStar Clean Energy has variable interests in T.E.S. Filer City, Grayling, Genesee, and Craven. While NorthStar Clean Energy owns 50 percent of each partnership, it is not the primary beneficiary of any of these partnerships because decision making is shared among unrelated parties, and no one party has the ability to direct the activities that most significantly impact the entities' economic performance, such as operations and maintenance, plant dispatch, and fuel strategy. The partners must agree on all major decisions for each of the partnerships.

Presented in the following table is information about these partnerships, which are accounted for using the equity method:

Name	Nature of the Entity	Nature of NorthStar Clean Energy's Involvement
T.E.S. Filer City	Coal-fueled power generator	Long-term PPA between partnership and Consumers Employee assignment agreement
Grayling	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers ¹ Operating and management contract
Genesee	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers ¹ Operating and management contract
Craven	Wood waste-fueled power generator	Operating and management contract

¹ Reduced dispatch agreements allow the facilities to be dispatched based on the market price of power compared with the cost of production of the plants. This results in fuel cost savings that each partnership shares with Consumers' customers.

The creditors of these partnerships do not have recourse to the general credit of CMS Energy, NorthStar Clean Energy, or Consumers. NorthStar Clean Energy's maximum risk exposure to these partnerships is generally limited to its investment in the partnerships, which is included in investments on CMS Energy's consolidated balance sheets in the amount of \$54 million at December 31, 2025 and \$64 million at December 31, 2024.

20: Exit Activities and Asset Sales

J.H. Campbell Retirement: Under its integrated resource plan, Consumers had planned to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through the planned retirement, Consumers implemented a retention incentive program. Consumers made final payments under this retention plan in November 2025. The aggregate cost of this program was \$48 million, which has been deferred as a regulatory asset. The MPSC has approved recovery of these retention costs over three years.

The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. As a result, Consumers has implemented retention measures to ensure appropriate staffing levels and expects to incur up to \$4 million during each 90-day emergency order period. Consumers will seek recovery of these retention costs from FERC, consistent with rate recovery sought for other costs of complying with the emergency orders. For additional information on the emergency orders associated with J.H. Campbell, see Note 3, Regulatory Matters.

Presented in the following table is a reconciliation of the retention benefit liability recorded in other current liabilities on Consumers' consolidated balance sheets:

Year Ended December 31	<i>In Millions</i>	
	2025	2024
Retention benefit liability at beginning of period	\$ 14	\$ 16
Costs deferred as a regulatory asset	7	8
Costs paid or settled	(19)	(10)
Retention benefit liability at the end of the period	\$ 2	\$ 14

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, for which Consumers filed in October 2025. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At December 31, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of CMS Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of CMS Energy Corporation and its subsidiaries (the “Company”) as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes and financial statement schedules listed in the index appearing under Item 15 (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of New Regulatory Matters

As described in Note 3 to the consolidated financial statements, the Company is a utility and must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, the Company records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by a non-regulated business. As of December 31, 2025 the Company has recognized a total of \$3,459 million of regulatory assets, \$4,176 million of regulatory liabilities, \$38 million of accrued revenues, and \$28 million of accrued rate refunds. As described by management, there are multiple participants to rate case proceedings who often challenge various aspects of those proceedings, including the prudence of the Company's policies and practices. These participants often seek cost disallowances and other relief and have appealed significant decisions reached by the regulators. The recovery of regulatory assets and the settlement of regulatory liabilities are contingent upon the outcomes of rate cases and regulatory proceedings. The principal considerations for our determination that performing procedures relating to accounting for the effects of new regulatory matters is a critical audit matter are (i) the high degree of auditor judgment and subjectivity applied to evaluate management's assessment of the potential outcomes and related accounting impacts associated with pending rate case proceedings; (ii) in some cases, the significant audit effort necessary to assess contrary evidence from various parties involved in rate case proceedings; and (iii) the significant audit effort necessary to evaluate audit evidence related to the recovery of regulatory assets and the settlement of regulatory liabilities. Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to

management's assessment of regulatory proceedings, including the probability of recovering incurred costs and the related accounting and disclosure impacts. These procedures also included, among others, (i) evaluating the Company's correspondence with regulators; (ii) evaluating the reasonableness of management's assessment regarding whether recovery of regulatory assets and settlement of regulatory liabilities is probable; (iii) evaluating the sufficiency of the disclosures in the consolidated financial statements; and (iv) testing, on a sample basis, the regulatory assets and liabilities, including those subject to pending rate cases and regulatory proceedings, based on (a) provisions and formulas outlined in rate orders; (b) other regulatory correspondence; and (c) application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 10, 2026

We have served as the Company's auditor since 2007.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Consumers Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Consumers Energy Company and its subsidiaries (the “Company”) as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes and financial statement schedule listed in the index appearing under Item 15 (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of New Regulatory Matters

As described in Note 3 to the consolidated financial statements, the Company is a utility and must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, the Company records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by a non-regulated business. As of December 31, 2025 the Company has recognized a total of \$3,459 million of regulatory assets, \$4,176 million of regulatory liabilities, \$38 million of accrued revenues, and \$28 million of accrued rate refunds. As described by management, there are multiple participants to rate case proceedings who often challenge various aspects of those proceedings, including the prudence of the Company's policies and practices. These participants often seek cost disallowances and other relief and have appealed significant decisions reached by the regulators. The recovery of regulatory assets and the settlement of regulatory liabilities are contingent upon the outcomes of rate cases and regulatory proceedings. The principal considerations for our determination that performing procedures relating to accounting for the effects of new regulatory matters is a critical audit matter are (i) the high degree of auditor judgment and subjectivity applied to evaluate management's assessment of the potential outcomes and related accounting impacts associated with pending rate case proceedings; (ii) in some cases, the significant audit effort necessary to assess contrary evidence from various parties involved in rate case proceedings; and (iii) the significant audit effort necessary to evaluate audit evidence related to the recovery of regulatory assets and the settlement of regulatory liabilities. Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to

management's assessment of regulatory proceedings, including the probability of recovering incurred costs and the related accounting and disclosure impacts. These procedures also included, among others, (i) evaluating the Company's correspondence with regulators; (ii) evaluating the reasonableness of management's assessment regarding whether recovery of regulatory assets and settlement of regulatory liabilities is probable; (iii) evaluating the sufficiency of the disclosures in the consolidated financial statements; and (iv) testing, on a sample basis, the regulatory assets and liabilities, including those subject to pending rate cases and regulatory proceedings, based on (a) provisions and formulas outlined in rate orders; (b) other regulatory correspondence; and (c) application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 10, 2026

We have served as the Company's auditor since 2007.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

CMS Energy

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures: Under the supervision and with the participation of management, including its CEO and CFO, CMS Energy conducted an evaluation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on such evaluation, CMS Energy's CEO and CFO have concluded that its disclosure controls and procedures were effective as of December 31, 2025.

Management's Annual Report on Internal Control Over Financial Reporting: CMS Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). CMS Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of CMS Energy
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of CMS Energy are being made only in accordance with authorizations of management and directors of CMS Energy
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of CMS Energy's assets that could have a material effect on its financial statements

Management, including its CEO and CFO, does not expect that its internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Under the supervision and with the participation of management, including its CEO and CFO, CMS Energy conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2025. In making this evaluation, management used the criteria set forth in the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on such evaluation, CMS Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2025. The effectiveness of CMS Energy's internal control over financial reporting as of December 31, 2025 has

been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting: There have not been any changes in CMS Energy's internal control over financial reporting during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Consumers

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures: Under the supervision and with the participation of management, including its CEO and CFO, Consumers conducted an evaluation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on such evaluation, Consumers' CEO and CFO have concluded that its disclosure controls and procedures were effective as of December 31, 2025.

Management's Annual Report on Internal Control Over Financial Reporting: Consumers' management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Consumers' internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Consumers
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of Consumers are being made only in accordance with authorizations of management and directors of Consumers
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of Consumers' assets that could have a material effect on its financial statements

Management, including its CEO and CFO, does not expect that its internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Under the supervision and with the participation of management, including its CEO and CFO, Consumers conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2025. In making this evaluation, management used the criteria set forth in the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on such evaluation, Consumers' management concluded that its internal control over financial reporting was effective as of December 31, 2025. The effectiveness of Consumers' internal control over financial reporting as of December 31, 2025 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting: There have not been any changes in Consumers' internal control over financial reporting during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

CMS Energy

CMS Energy has adopted an insider trading compliance policy and program applicable to directors, executive officers and employees, as well as CMS Energy itself. CMS Energy believes this policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the New York Stock Exchange listing standards. A copy of the insider trading policy is filed as Exhibit 19.1 to this Form 10-K. Additional information that is required in Item 10 of this Form 10-K regarding executive officers is included in the Item 1. Business—Information About CMS Energy’s and Consumers’ Executive Officers section, which is incorporated by reference herein.

Information that is required in Item 10 of this Form 10-K regarding directors, executive officers, and corporate governance is incorporated by reference from CMS Energy’s and Consumers’ definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Code of Ethics

CMS Energy has adopted an employee code of ethics, entitled “CMS Energy Code of Conduct and Guide to Ethical Business Behavior” (Employee Code) that applies to its CEO, CFO, and CAO, as well as all other officers and employees of CMS Energy and its affiliates. The Employee Code is administered by the Chief Compliance Officer of CMS Energy, who reports directly to the Audit Committee. CMS Energy has also adopted a director code of ethics entitled “Board of Directors Code of Conduct and Guide to Ethical Business Behavior” (Director Code) that applies to its directors. The Director Code is administered by the Audit Committee. Any alleged violation of the Director Code by a director will be investigated by disinterested members of the Audit Committee, or if none, by disinterested members of the entire Board. The Employee Code and Director Code and any waivers of, or amendments or exceptions to, a provision of the Employee Code that applies to CMS Energy’s CEO, CFO, CAO or persons performing similar functions and any waivers of, or amendments or exceptions to, a provision of CMS Energy’s Director Code will be disclosed on CMS Energy’s website at www.cmsenergy.com/corporate-governance/compliance-and-ethics.

Consumers

Consumers has adopted an insider trading compliance policy and program applicable to directors, executive officers and employees, as well as Consumers itself. Consumers believes this policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the New York Stock Exchange listing standards. A copy of the insider trading policy is filed as Exhibit 19.1 to this Form 10-K. Additional information that is required in Item 10 of this Form 10-K regarding executive officers is included in the Item 1. Business—Information About CMS Energy’s and Consumers’ Executive Officers section, which is incorporated by reference herein.

Information that is required in Item 10 of this Form 10-K regarding directors, executive officers, and corporate governance is incorporated by reference from CMS Energy’s and Consumers’ definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement

will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Code of Ethics

Consumers has adopted an employee code of ethics, entitled “CMS Energy Code of Conduct and Guide to Ethical Business Behavior” (Employee Code) that applies to its CEO, CFO, and CAO, as well as all other officers and employees of Consumers and its affiliates. The Employee Code is administered by the Chief Compliance Officer of Consumers, who reports directly to the Audit Committee. Consumers has also adopted a director code of ethics entitled “Board of Directors Code of Conduct and Guide to Ethical Business Behavior” (Director Code) that applies to its directors. The Director Code is administered by the Audit Committee. Any alleged violation of the Director Code by a director will be investigated by disinterested members of the Audit Committee, or if none, by disinterested members of the entire Board. The Employee Code and Director Code and any waivers of, or amendments or exceptions to, a provision of the Employee Code that applies to Consumers’ CEO, CFO, CAO or persons performing similar functions and any waivers of, or amendments or exceptions to, a provision of Consumers’ Director Code will be disclosed on Consumers’ website at www.cmsenergy.com/corporate-governance/compliance-and-ethics.

Item 11. Executive Compensation

See the note below.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Securities Authorized for Issuance Under Equity Compensation Plans

Presented in the following table is information regarding CMS Energy’s equity compensation plans as of December 31, 2025:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plan approved by shareholders	—	\$ —	3,965,601

Also see the note below.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See the note below.

Item 14. Principal Accountant Fees and Services

See the note below.

NOTE: Information that is required by Part III—Items 11, 12, 13, and 14 of this Form 10-K is incorporated by reference from CMS Energy’s and Consumers’ definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Part IV

Item 15. Exhibits and Financial Statement Schedules

The following financial statements are filed as part of this report under Item 8. Financial Statements and Supplementary Data:

- Consolidated Statements of Income of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Comprehensive Income of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Cash Flows of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Balance Sheets of CMS Energy at December 31, 2025 and 2024
- Consolidated Statements of Changes in Equity of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Income of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Comprehensive Income of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Cash Flows of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Balance Sheets of Consumers at December 31, 2025 and 2024
- Consolidated Statements of Changes in Equity of Consumers for the years ended December 31, 2025, 2024, and 2023
- Notes to the Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm for CMS Energy
- Report of Independent Registered Public Accounting Firm for Consumers

The following financial statement schedules are included below:

- Schedule I — Condensed Financial Information of Registrant, CMS Energy—Parent Company at December 31, 2025 and 2024 and for the years ended December 31, 2025, 2024, and 2023
- Schedule II — Valuation and Qualifying Accounts and Reserves of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Schedule II — Valuation and Qualifying Accounts and Reserves of Consumers for the years ended December 31, 2025, 2024, and 2023

Schedule I — Condensed Financial Information of Registrant

CMS Energy—Parent Company Condensed Statements of Income

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Operating Expenses			
Other operating expenses	\$ 9	\$ 10	\$ 10
Total operating expenses	9	10	10
Operating Loss	(9)	(10)	(10)
Other Income (Expense)			
Equity earnings of subsidiaries	1,189	1,061	929
Nonoperating retirement benefits, net	(1)	(1)	(1)
Other income	69	45	31
Other expense	(2)	—	—
Total other income	1,255	1,105	959
Interest Charges			
Interest on long-term debt	266	205	201
Intercompany interest expense and other	10	10	10
Total interest charges	276	215	211
Income Before Income Taxes	970	880	738
Income Tax Benefit	(39)	(19)	(20)
Net Income Attributable to CMS Energy	1,009	899	758
Preferred Stock Dividends	10	10	10
Net Income Available to Common Stockholders	\$ 999	\$ 889	\$ 748

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company Condensed Statements of Cash Flows

	<i>In Millions</i>		
Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net cash provided by operating activities	\$ 817	\$ 774	\$ 595
Cash Flows from Investing Activities			
Capital expenditures	(1)	(1)	—
Investment in subsidiaries	(1,062)	(535)	(630)
Investment in debt securities – intercompany	(109)	(288)	(293)
Decrease (increase) in notes receivable – intercompany	(309)	21	55
Proceeds from DB SERP investments	3	—	—
Net cash used in investing activities	(1,478)	(803)	(868)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	2,110	490	800
Issuance of common stock	525	286	192
Retirement of long-term debt	(850)	(250)	—
Payment of dividends on common and preferred stock	(663)	(626)	(579)
Debt issuance costs and financing fees	(39)	(10)	(20)
Change in notes payable – intercompany	3	(6)	(7)
Net cash provided by (used in) financing activities	1,086	(116)	386
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	425	(145)	113
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	4	149	36
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	\$ 429	\$ 4	\$ 149

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company Condensed Balance Sheets

ASSETS

	<i>In Millions</i>	
December 31	2025	2024
Current Assets		
Cash and cash equivalents	\$ 429	\$ 4
Notes and accrued interest receivable – intercompany	350	40
Accounts receivable – intercompany and related parties	8	8
Prepayments and other current assets	1	1
Total current assets	788	53
Other Non-current Assets		
Property, plant, and equipment	1	1
Deferred income taxes	105	150
Investments in subsidiaries	13,724	12,400
Investment in debt securities – intercompany	710	591
Other investments	8	9
Other	23	21
Total other non-current assets	14,571	13,172
Total Assets	\$ 15,359	\$ 13,225

LIABILITIES AND EQUITY

	<i>In Millions</i>	
December 31	2025	2024
Current Liabilities		
Current portion of long-term debt	\$ 300	\$ 740
Accounts and notes payable – intercompany	89	74
Accrued interest, including intercompany	43	34
Accrued taxes	41	16
Other current liabilities	8	6
Total current liabilities	481	870
Non-current Liabilities		
Long-term debt	5,906	4,226
Notes payable – intercompany	96	100
Postretirement benefits	13	14
Other non-current liabilities	14	17
Total non-current liabilities	6,029	4,357
Equity		
Common stock	3	3
Other stockholders' equity	8,622	7,771
Total common stockholders' equity	8,625	7,774
Preferred stock	224	224
Total equity	8,849	7,998
Total Liabilities and Equity	\$ 15,359	\$ 13,225

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company Notes to the Condensed Financial Statements

1: Basis of Presentation

CMS Energy's condensed financial statements have been prepared on a parent-only basis. In accordance with Rule 12-04 of Regulation S-X, these parent-only financial statements do not include all of the information and notes required by GAAP for annual financial statements, and therefore these parent-only financial statements and other information included should be read in conjunction with CMS Energy's audited consolidated financial statements contained within Item 8. Financial Statements and Supplementary Data.

2: Guarantees

CMS Energy has issued guarantees with a maximum potential obligation of \$1.3 billion on behalf of some of its wholly owned subsidiaries and related parties. CMS Energy's maximum potential obligation consists primarily of potential payments:

- to third parties under certain commodity purchase and sales agreements entered into by CMS ERM and other subsidiaries of NorthStar Clean Energy
- to tax equity investors that hold membership interests in certain VIEs held by NorthStar Clean Energy
- to EGLE on behalf of CMS Land and CMS Capital, for environmental remediation obligations at Bay Harbor
- to the DOE on behalf of Consumers, in connection with Consumers' 2011 settlement agreement with the DOE regarding damages resulting from the department's failure to accept spent nuclear fuel from nuclear power plants formerly owned by Consumers

The expiration dates of these guarantees vary, depending upon contractual provisions or upon the statute of limitations under the relevant governing law.

Schedule II — Valuation and Qualifying Accounts and Reserves

CMS Energy Corporation

Years Ended December 31, 2025, 2024, and 2023

<i>In Millions</i>					
Description	Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
Allowance for uncollectible accounts¹					
2025	\$ 23	\$ 40	\$ —	\$ 36	\$ 27
2024	21	33	—	31	23
2023	27	34	—	40	21
Deferred tax valuation allowance					
2025	\$ 1	\$ 1	\$ —	\$ —	\$ 2
2024	2	—	—	1	1
2023	2	—	—	—	2

¹ Deductions represent write-offs of uncollectible accounts, net of recoveries.

Consumers Energy Company

Years Ended December 31, 2025, 2024, and 2023

<i>In Millions</i>					
Description	Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
Allowance for uncollectible accounts¹					
2025	\$ 23	\$ 40	\$ —	\$ 36	\$ 27
2024	21	33	—	31	23
2023	27	34	—	40	21

¹ Deductions represent write-offs of uncollectible accounts, net of recoveries.

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Exhibit Index

The agreements included as exhibits to this Form 10-K filing are included solely to provide information regarding the terms of the agreements and are not intended to provide any other factual or disclosure information about CMS Energy, Consumers, or other parties to the agreements. The agreements may contain representations and warranties made by each of the parties to each of the agreements that were made exclusively for the benefit of the parties involved in each of the agreements and should not be treated as statements of fact. The representations and warranties were made as a way to allocate risk if one or more of those statements prove to be incorrect. The statements were qualified by disclosures of the parties to each of the agreements that may not be reflected in each of the agreements. The agreements may apply standards of materiality that are different than standards applied to other investors. Additionally, the statements were made as of the date of the agreements or as specified in the agreements and have not been updated. The representations and warranties may not describe the actual state of affairs of the parties to each agreement.

Additional information about CMS Energy and Consumers may be found in this filing, at www.cmsenergy.com, at www.consumersenergy.com, and through the SEC's website at www.sec.gov.

Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
3.1 ¹	1-9513	3.1	— Restated Articles of Incorporation of CMS Energy, effective June 1, 2004, as amended from time to time (Form 10-Q for the quarterly period ended June 30, 2024)
3.2 ¹	1-9513	3.2	— CMS Energy Bylaws, amended and restated effective February 8, 2016 (Form 8-K filed February 8, 2016)
3.3	1-5611	3(c)	— Restated Articles of Incorporation of Consumers effective June 7, 2000 (Form 10-K for the fiscal year ended December 31, 2000)
3.4	1-5611	3.2	— Consumers Bylaws, amended and restated as of January 24, 2013 (Form 8-K filed January 29, 2013)
4.1	2-65973	(b)(1)–4	— Indenture dated as of September 1, 1945 between Consumers and Chemical Bank (successor to Manufacturers Hanover Trust Company), as Trustee, including therein indentures supplemental thereto through the Forty-third Supplemental Indenture dated as of May 1, 1979 (Form S-16 filed November 13, 1979) <i>Indentures Supplemental thereto:</i>
4.1.a	1-5611	4.2	— 104th dated as of 8/11/05 (Form 8-K filed August 11, 2005)
4.1.b	1-5611	4.1	— 112th dated as of 9/1/10 (Form 8-K filed September 7, 2010)
4.1.c	1-5611	4.1	— 113th dated as of 10/15/10 (Form 8-K filed October 20, 2010)
4.1.d	1-5611	4.1	— 114th dated as of 3/31/11 (Form 8-K filed April 6, 2011)
4.1.e	1-5611	4.1	— 120th dated as of 12/17/12 (Form 8-K filed December 20, 2012)
4.1.f	1-5611	4.1	— 121st dated as of 5/17/13 (Form 8-K filed May 17, 2013)
4.1.g	1-5611	4.1	— 123rd dated as of 12/20/13 (Form 8-K filed December 27, 2013)
4.1.h	1-5611	4.1	— 124th dated as of 8/18/2014 (Form 8-K filed August 18, 2014)
4.1.i	1-5611	4.1	— 125th dated as of 11/6/2015 (Form 8-K filed November 6, 2015)
4.1.j	1-5611	4.1	— 127th dated as of 8/10/16 (Form 8-K filed August 10, 2016)

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Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
4.1.k	1-5611	4.1	— 128th dated as of 2/22/17 (Form 8-K filed February 22, 2017)
4.1.l	1-5611	4.1	— 129th dated as of 9/28/17 (Form 8-K filed September 28, 2017)
4.1.m	1-5611	4.1	— 130th dated as of 11/15/17 (Form 8-K filed November 15, 2017)
4.1.n	1-5611	4.1	— 131st dated as of 5/14/18 (Form 8-K filed May 14, 2018)
4.1.o	1-5611	4.1	— 132nd dated as of 6/5/18 (Form 8-K filed June 5, 2018)
4.1.p	1-5611	4.1	— 133rd dated as of 10/1/18 (Form 8-K filed October 1, 2018)
4.1.q	1-5611	4.1	— 134th dated as of 11/13/18 (Form 8-K filed November 13, 2018)
4.1.r	1-5611	4.1	— 135th dated as of 5/28/19 (Form 8-K filed May 28, 2019)
4.1.s	1-5611	4.1	— 136th dated as of 9/3/19 (Form 8-K filed September 3, 2019)
4.1.t	1-5611	4.1	— 137th dated as of 9/19/19 (Form 8-K filed September 19, 2019)
4.1.u	1-5611	4.3	— 138th dated as of 10/1/19 (Form 10-Q for the quarterly period ended September 30, 2019)
4.1.v	1-5611	4.1	— 139th dated as of 3/26/20 (Form 8-K filed March 26, 2020)
4.1.w	1-5611	4.1	— 140th dated as of 5/13/20 (Form 8-K filed May 13, 2020)
4.1.x	1-5611	4.1	— 141st dated as of 5/20/20 (Form 8-K filed May 20, 2020)
4.1.y	1-5611	4.1	— 142nd dated as of 10/7/20 (Form 8-K filed October 7, 2020)
4.1.z	1-5611	4.1	— 144th dated as of 8/12/21 (Form 8-K filed August 12, 2021)
4.1.aa	1-5611	4.1	— 145th dated as of 8/11/22 (Form 8-K filed August 11, 2022)
4.1.bb	1-5611	4.1	— 146th dated as of 12/14/22 (Form 8-K filed December 15, 2022)
4.1.cc	1-5611	4.1	— 147th dated as of 1/10/23 (Form 8-K filed January 10, 2023)
4.1.dd	1-5611	4.1	— 148th dated as of 2/23/23 (Form 8-K filed February 23, 2023)
4.1.ee	1-5611	4.1	— 149th dated as of 5/30/23 (Form 8-K filed May 30, 2023)
4.1.ff	1-5611	4.1	— 150th dated as of 8/4/23 (Form 8-K filed August 4, 2023)
4.1.gg	1-5611	4.1	— 151st dated as of 1/9/24 (Form 8-K filed January 9, 2024)
4.1.hh	1-5611	4.1	— 152nd dated as of 8/5/24 (Form 8-K filed August 5, 2024)
4.1.ii	1-5611	4.1	— 153rd dated as of 5/2/25 (Form 8-K filed May 2, 2025)
4.1.jj	1-5611	4.1	— 154th dated as of 11/21/25 (Form 8-K filed November 21, 2025)
4.1.kk			— 155th dated as of 11/28/2025
4.2	1-5611	(4)(b)	— Indenture dated as of January 1, 1996 between Consumers and The Bank of New York Mellon, as Trustee (Form 10-K for the fiscal year ended December 31, 1995)
4.3	1-5611	(4)(c)	— Indenture dated as of February 1, 1998 between Consumers and The Bank of New York Mellon (formerly The Chase Manhattan Bank), as Trustee (Form 10-K for the fiscal year ended December 31, 1997)
4.4 ¹	33-47629	(4)(a)	— Indenture dated as of September 15, 1992 between CMS Energy and NBD Bank, as Trustee (Form S-3 filed May 1, 1992) <i>Indentures Supplemental thereto:</i>
4.4.a ¹	1-9513	4.1	— 29th dated as of 3/22/13 (Form 8-K filed March 22, 2013)
4.4.b ¹	1-9513	4.2	— 31st dated as of 2/27/14 (Form 8-K filed February 27, 2014)

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Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
4.4.c ¹	1-9513	4.1	— 33rd dated as of 5/5/16 (Form 8-K filed May 5, 2016)
4.4.d ¹	1-9513	4.1	— 34th dated as of 11/3/16 (Form 8-K filed November 3, 2016)
4.4.e ¹	1-9513	4.1	— 35th dated as of 2/13/17 (Form 8-K filed February 13, 2017)
4.5 ¹	1-9513	(4a)	— Indenture dated as of June 1, 1997 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed July 1, 1997)
			<i>Indentures Supplemental thereto:</i>
4.5.a ¹	1-9513	4.5.a	— 5th dated as of 2/13/18 (Form 10-K for the fiscal year ended December 31, 2017)
4.5.b ¹	1-9513	4.1	— 6th dated as of 3/8/18 (Form 8-K filed March 8, 2018)
4.5.c ¹	1-9513	4.1	— 7th dated as of 9/26/18 (Form 8-K filed September 26, 2018)
4.5.d ¹	1-9513	4.1	— 8th dated as of 2/20/19 (Form 8-K filed February 20, 2019)
4.5.e ¹	1-9513	4.1	— 9th dated as of 5/28/20 (Form 8-K filed May 28, 2020)
4.5.f ¹	1-9513	4.1	— 10th dated as of 11/25/20 (Form 8-K filed November 25, 2020)
4.5.g ¹	1-9513	4.1	— 11th dated as of 2/21/25 (Form 8-K filed February 21, 2025)
4.6 ¹	1-9513	4.1	— Indenture dated as of May 5, 2023 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed May 5, 2023)
4.7 ¹	1-9513	4.1	— Indenture dated as of November 6, 2025 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed November 6, 2025)
4.8 ¹	1-9513	4.6	— Description of CMS Energy Securities (Form 10-K for the fiscal year ended December 31, 2021)
4.9	1-5611	4.7	— Description of Consumers Securities (Form 10-K for the fiscal year ended December 31, 2019)
4.10 ¹	1-9513	4.2	— Deposit Agreement, dated as of July 1, 2021, among CMS Energy, Equiniti Trust Company, and the holders from time to time of the depositary receipts described therein, including Form of Depositary Receipt (Form 8-K filed July 1, 2021)
10.1 ²	1-9513	10.1	— CMS Energy 2020 Performance Incentive Stock Plan, effective June 1, 2020 (Form 8-K filed May 5, 2020)
10.2 ²	1-9513	10.2	— CMS Energy’s Deferred Salary Savings Plan, as amended and restated, effective January 1, 2022 (Form 10-K for the fiscal year ended December 31, 2023)
10.3 ²	1-9513	10.5	— CMS Energy and Consumers Directors’ Deferred Compensation Plan, effective as of November 30, 2007 (Form 10-K for the fiscal year ended December 31, 2014)
10.4 ²	1-9513	10.6	— Supplemental Executive Retirement Plan for Employees of CMS Energy/Consumers effective on January 1, 1982 and as amended effective April 1, 2011 (Form 10-Q for the quarterly period ended March 31, 2011)

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Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
10.5 ²	1-9513	10.5	— Defined Contribution Supplemental Executive Retirement Plan, amended December 21, 2023, effective January 1, 2024 (Form 10-K for the fiscal year ended December 31, 2023)
10.6 ²	1-9513	10.2	— Form of Officer Separation Agreement as of July 1, 2023 (Form 10-Q for the quarterly period ended June 30, 2023)
10.7 ¹	1-9513	(10)(y)	— Environmental Agreement dated as of June 1, 1990 made by CMS Energy to The Connecticut National Bank and Others (Form 10-K for the fiscal year ended December 31, 1990)
10.8 ^{1,2}	1-9513	(10)(a)	— Form of Indemnification Agreement between CMS Energy and its Directors, effective as of November 1, 2007 (Form 10-Q for the quarterly period ended September 30, 2007)
10.9 ²	1-5611	(10)(b)	— Form of Indemnification Agreement between Consumers and its Directors, effective as of November 1, 2007 (Form 10-Q for the quarterly period ended September 30, 2007)
10.10 ²	1-9513	10.10	— CMS Incentive Compensation Plan for CMS Energy and Consumers Officers as amended, effective as of January 27, 2022 (Form 10-K for the fiscal year ended December 31, 2021)
10.11 ²	1-9513	10.3	— Form of Change in Control Agreement as of July 1, 2023 (Form 10-Q for the quarterly period ended June 30, 2023)
10.12 ²	1-9513	10.12	— Annual Employee Incentive Compensation Plan for Consumers amended December 11, 2023, effective July 1, 2023 (Form 10-K for the fiscal year ended December 31, 2023)
10.13 ^{1,2}	1-9513	10.1	— Annual NorthStar Clean Energy Employee Incentive Compensation Plan as amended, effective as of May 1, 2025 (Form 10-Q for the quarterly period ended June 30, 2025)
10.14 ¹	1-9513	10.1	— \$750 million Sixth Amended and Restated Revolving Credit Agreement dated as of November 21, 2025 among CMS Energy, the Banks, as defined therein, and Barclays Bank PLC, as Agent (Form 8-K filed November 21, 2025)
10.15	1-5611	10.2	— \$1.1 billion Seventh Amended and Restated Revolving Credit Agreement dated as of November 21, 2025 among Consumers, the Banks, as defined therein, and JPMorgan Chase Bank, N.A., as Agent (Form 8-K filed November 21, 2025)
10.16	1-5611	10.1	— \$250 million Amended and Restated Revolving Credit Agreement dated as of November 19, 2018 among Consumers, the Banks, as defined therein, and The Bank of Nova Scotia, as Agent (Form 8-K filed November 20, 2018)
10.16.a	1-5611	10.1	— Description of the Extension to the Amended and Restated \$250 million Secured Revolving Credit Agreement (Form 8-K filed November 19, 2019)
10.16.b	1-5611	10.1	— Description of the Second Extension to the Amended and Restated \$250 million Secured Revolving Credit Agreement (Form 8-K filed November 19, 2020)

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Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
10.16.c	1-5611	10.1	— Description of the Third Extension to the Amended and Restated \$250 million Secured Revolving Credit Agreement (Form 8-K filed November 22, 2021)
10.16.d	1-5611	10.1	— First Amendment to the Amended and Restated \$250 million Secured Revolving Credit Agreement (Form 8-K filed November 29, 2022)
10.16.e	1-5611	10.1	— Amendment No. 2 to the Amended and Restated \$250 million Secured Revolving Credit Agreement (Form 8-K filed November 29, 2023)
10.16.f	1-5611	10.3	— Third Amendment to the Amended and Restated \$250 Million Secured Revolving Credit Agreement (Form 8-K filed November 21, 2025)
10.17 ²	1-9513	10.1	— Consumers and other CMS Energy Companies Retired Executives Survivor Benefit Plan for Management/Executive Employees, distributed July 1, 2011 (Form 10-Q for the quarterly period ended September 30, 2011)
10.18	1-5611	10.1	— Form of Commercial Paper Dealer Agreement between Consumers, as Issuer, and the Dealer party thereto (Form 10-Q for the quarterly period ended September 30, 2014)
10.19	1-5611	10.1	— Purchase and Sale Agreement dated June 21, 2021 by and among Consumers and New Covert Generating Company, LLC (Form 8-K filed June 23, 2021)
10.19.a	1-5611	10.4	— Amendment No. 1 dated as of May 31, 2023 to the Purchase and Sale Agreement, dated June 21, 2021 by and among Consumers and New Covert Generating Company, LLC (Form 10-Q for the quarterly period ending June 30, 2023)
10.20 ²	1-9513	10.22	— Annual Employee Incentive Compensation Plan for Consumers amended and restated effective January 1, 2024 (Form 10-K for the fiscal year ended December 31, 2023)
19.1	1-9513	19.1	— Policy Prohibiting Illegal Insider Trading (Form 10-K for the fiscal year ended December 31, 2024)
21.1			— Subsidiaries of CMS Energy and Consumers
23.1			— Consent of PricewaterhouseCoopers LLP for CMS Energy
23.2			— Consent of PricewaterhouseCoopers LLP for Consumers
31.1			— CMS Energy’s certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2			— CMS Energy’s certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3			— Consumers’ certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.4			— Consumers’ certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

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Exhibits	Previously Filed		Description
	With File Number	As Exhibit Number	
32.1			— CMS Energy’s certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2			— Consumers’ certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1 ²	1-9513	97.1	— CMS Energy/Consumers Clawback Policy (Form 10-K for the fiscal year ended December 31, 2023)
99.1 ¹	333-275106	99.1	— CMS Energy Stock Purchase Plan, as amended and restated October 20, 2023 (Form S-3ASR filed October 20, 2023)
101.INS			— Inline XBRL Instance Document
101.SCH			— Inline XBRL Taxonomy Extension Schema
101.CAL			— Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF			— Inline XBRL Taxonomy Extension Definition Linkbase
101.LAB			— Inline XBRL Taxonomy Extension Labels Linkbase
101.PRE			— Inline XBRL Taxonomy Extension Presentation Linkbase
104			— Cover Page Interactive Data File (the cover page XBRL tags are embedded in the Inline XBRL document)

¹ Obligations of CMS Energy or its subsidiaries, but not of Consumers.

² Management contract or compensatory plan or arrangement.

Exhibits that have been previously filed with the SEC, designated above, are incorporated herein by reference and made a part hereof.

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, CMS Energy Corporation has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

/s/ Garrick J. Rochow

Name: Garrick J. Rochow

Title: President and Chief Executive Officer

Date: February 10, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of CMS Energy Corporation and in the capacities indicated and on February 10, 2026.

/s/ Garrick J. Rochow

Garrick J. Rochow
President, Chief Executive Officer, and Director
(Principal Executive Officer)

/s/ Rejji P. Hayes

Rejji P. Hayes
Executive Vice President and Chief Financial
Officer
(Principal Financial Officer)

/s/ Scott B. McIntosh

Scott B. McIntosh
Vice President, Controller, and Chief
Accounting Officer
(Controller)

/s/ Deborah H. Butler

Deborah H. Butler, Director

/s/ Ralph Izzo

Ralph Izzo, Director

/s/ John G. Russell

John G. Russell, Director

/s/ Suzanne F. Shank

Suzanne F. Shank, Director

/s/ Myrna M. Soto

Myrna M. Soto, Director

/s/ John G. Sznewajs

John G. Sznewajs, Director

/s/ Ronald J. Tanski

Ronald J. Tanski, Director

/s/ Laura H. Wright

Laura H. Wright, Director

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Consumers Energy Company has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

/s/ Garrick J. Rochow

Name: Garrick J. Rochow

Title: President and Chief Executive Officer

Date: February 10, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of Consumers Energy Company and in the capacities indicated and on February 10, 2026.

/s/ Garrick J. Rochow

Garrick J. Rochow
President, Chief Executive Officer, and Director
(Principal Executive Officer)

/s/ Rejji P. Hayes

Rejji P. Hayes
Executive Vice President and Chief Financial
Officer
(Principal Financial Officer)

/s/ Scott B. McIntosh

Scott B. McIntosh
Vice President, Controller, and Chief
Accounting Officer
(Controller)

/s/ Deborah H. Butler

Deborah H. Butler, Director

/s/ Ralph Izzo

Ralph Izzo, Director

/s/ John G. Russell

John G. Russell, Director

/s/ Suzanne F. Shank

Suzanne F. Shank, Director

/s/ Myrna M. Soto

Myrna M. Soto, Director

/s/ John G. Sznewajs

John G. Sznewajs, Director

/s/ Ronald J. Tanski

Ronald J. Tanski, Director

/s/ Laura H. Wright

Laura H. Wright, Director

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CMS Energy Corporation
Consumers Energy Company
One Energy Plaza
Jackson, MI 49201-2357



Michael Roeder
President, Indiana Region
Government Affairs
Mike.Roeder@CenterPointEnergy.com

P.O. Box 209
Evansville, IN 47702-0209
317-260-5302

February 17, 2026

The Honorable Chris Wright
Secretary of Energy
United States Department of Energy
1000 Independence Ave., SW
Washington, DC 20585
the.secretary@hq.doe.gov

Dear Secretary Wright:

As a proud Indiana energy provider, we remain focused on the state's energy pillars of reliability, resilience, affordability, and stability. While we remain engaged complying with the current December 23, 2025, DOE 202c order, maintaining F.B. Culley Unit 2 ("Unit 2") will require **substantial investment to support an inefficient and increasingly unreliable asset**, rather than advancing affordable and reliable service for customers in southwestern Indiana.

We respectfully request that the Department of Energy allow Order No. 202-25-13 (the "Order") to expire on March 23, 2026, and abstain from issuing subsequent Section 202(c) directives for Unit 2.

We acknowledge the concerns outlined in the Order and recognize the complexity inherent in balancing increasing demand with the obligation to serve the public interest. However, **Unit 2 accounts for less than 1% of the total installed capacity in MISO's North/Central region.**¹ In addition, current industry data shows sufficient capacity without Unit 2:

MISO members expect to meet their capacity needs through 2031, with more than 11 GWs of excess capacity.

- NERC's 2025 Long-Term Reliability Assessment reduces MISO's Capacity and Energy Risk level to "Normal" for 2026. The Assessment states, "**For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW**".²
- The 2025 OMS-MISO Survey shows **MISO members expect to meet their capacity needs through 2031, with more than 11 GWs of excess capacity.**³

We have adequate generation capacity – without Unit 2 – to meet MISO's Planning Reserve Margin Requirement through the 2027-2028 Planning Year – reflecting our commitment to continued system reliability.

Three consecutive IRPs concluded that retirement of Unit 2 is the most prudent option.

Affordability, reliability, and resiliency remain foundational elements of our Integrated Resource Planning (IRP) process, which guides our long-term resource decisions. Our three most recent IRPs – in 2016, 2019/2020, and 2023 – concluded that the retirement of Unit 2 was the most prudent option. The IRP analysis has repeatedly demonstrated that keeping the unit online would demand **costly investments to**

¹ MISO PY 2026-2027 Seasonal Preliminary PRA Report, Released January 28, 2026; [PY 2026-2027 Seasonal Preliminary PRA Report 01-28-2026738710.xlsx](#)

² North American Electric Reliability Corporation (NERC), Long-Term Reliability Assessment, Released January 2026 – Pages 8 and 42; https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

³ 2025 OMS-MISO Survey, Released June 6, 2025 – Slide 7; <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>

maintain operational reliability and environmental compliance. Consequently, Unit 2 was approved by MISO to cease operations on December 31, 2025.

Operational data from the Order's effective date (December 23, 2025) through February 8, 2026, support the IRP findings. Following is the operational status for Unit 2 over the past 48 days:

- **26 days:** Unit 2 was **on outage** due to equipment issues
- **5 days:** Unit 2 was on reserve shut down – available but **not economically dispatched** by MISO
- **17 days:** Unit 2 was online but **limited** to between 45MW and 78MW (net) due to maintenance issues.

Unit 2's performance during the recent MISO cold weather event underscores a pattern of unreliability of that unit. Although the unit was dispatched on January 24 – 25, 2026, Unit 2 was limited to 45MW (net) due to a significant derate. One day later, on January 26, systemic equipment failures forced another outage, further demonstrating the unit's ongoing inability to provide dependable service.

Safe operation beyond March 2026 requires an estimated 14 weeks of outages.

Safe and reliable operation beyond March 2026 hinges on major and costly interventions, including acid cleaning of the boiler and replacement of boiler tubes—necessitating a four-week or longer outage, with projected cost of approximately \$1.9 million – \$2.5 million. Additionally, Unit 2's turbine-generator is currently operating beyond the original equipment manufacturers overhaul specifications—significantly increasing the risk of catastrophic mechanical failure. To

avoid that, turbine overhaul is unavoidable, requiring extensive work made even more challenging by long lead times for critical components and a 10-week outage. The turbine-generator overhaul, together with other anticipated outage-related work, is currently estimated to result in total expenditures of approximately \$14 million – \$18 million. Our team continues evaluating additional operational factors as there may be additional investments needed, driving estimated costs higher. These factors make clear that extending the life of Unit 2 is neither practical nor financially responsible, underscoring the need for a more prudent and economically sound path forward.

Again, we respectfully request that the Department of Energy allow the current 202 Order to end on March 23, 2026, and abstain from issuing subsequent 202 Orders for Unit 2. We appreciate DOE's leadership in safeguarding the nation's electric reliability and trust that this request will be given full consideration.

Respectfully submitted,



Michael Roeder
CenterPoint Energy
President, Indiana Region

Cc: Indiana Gov. Mike Braun

THE PRESIDENT AND THE POWER GRID
Mich. L. Rev. Online (forthcoming 2026)

Alexandra B. Klass* & Dave Owen**

There is a sharp discontinuity between the second Trump administration's electricity policies and those of previous presidential administrations. President Trump has directed the Department of Energy to use statutory authority designed for wartime conditions and sudden emergencies to prevent electric utilities from retiring aging coal plants. In doing so, he has elevated the President's role in electric grid governance and reduced the primacy of the independent expert regulatory agency—the Federal Energy Regulatory Commission—that Congress authorized to govern electricity markets and grid reliability.

This Essay places these actions in historical context. It recounts the executive branch's role in electricity policy during the first part of the twentieth century, when the federal government responded to wartime crises by building new electricity supplies and actively managing existing electricity infrastructure. While these early and mid-twentieth century executive actions may superficially resemble present-day events, they were profoundly different. Even amid the urgency of wartime, the executive branch was laying the foundation for an integrated grid managed by expert government agencies, not through direct presidential decrees, and it was working for technological progress, not regression. Building on this history, this Essay then explains why the present-day shift from expert agencies to presidential power in electric grid governance matters. The most obvious reason is that it will carry heavy financial and environmental costs to consumers and the nation. But the increased assertion of presidential power in electric grid governance also has doctrinal significance in light of recent developments in Supreme Court jurisprudence governing statutory interpretation and presidential use of emergency authorities.

INTRODUCTION

In May 2025, the U.S. Department of Energy (“DOE”) ordered Consumers Energy, an electric utility serving Michigan, to halt the planned retirement of its J.H. Campbell power plant.¹ The 1,500-megawatt (“MW”) plant is the state’s

* James G. Degnan Professor of Law, University of Michigan Law School. We received extremely helpful comments on earlier drafts of this essay from Nick Bagley, Dan Deacon, Joel Eisen, Rob Glicksman, Leah Litman, Heather Payne, Ari Peskoe, and Hannah Wiseman. Sam Fiske, Meredith Folensbee, Meher Mann, Hazel Rosenblum-Sellers, and Connor Tooman provided excellent research assistance.

** Albert Abramson ’54 Distinguished Professor & Associate Dean for Research, UC Law San Francisco.

¹ *Federal Power Act Section 202(c): Midcontinent Independent System Operator (MISO)*, U.S. DEP’T OF ENERGY, <https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso> (DOE website linking to order and subsequent filings); *J.H. Campbell Complex Retirement*, CONSUMERS ENERGY, <https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement> (discussing power plant).

second-largest coal plant and one of its largest stationary sources of air pollution.² For Consumers Energy, this was a disruptive order. The 63-year-old plant was scheduled to permanently retire the following week, after years of planning and signoffs from all relevant state and federal regulators and grid operators.³ Consumers Energy had already spent hundreds of millions of dollars replacing the coal plant’s output with renewable energy and a new natural-gas-fired power plant.⁴ When the utility received the DOE order at the start of Memorial Day weekend, it had to turn on a dime to re-hire workers, obtain coal supplies at inflated prices, and begin incurring what in just a few months would become over \$100 million in losses, all to keep online an aging plant that the utility and grid operators had determined was no longer needed.⁵ Who should pay for those losses—only Consumers Energy ratepayers or all ratepayers in the region—and whether such costs should have been incurred at all are questions now being litigated in multiple forums.⁶

DOE’s order was unprecedented in multiple ways. In issuing the order, DOE relied on Section 202(c) of the Federal Power Act (“FPA”), which authorizes DOE to order the “temporary” connection of power plants or electric transmission facilities during “the continuance of any war” or “emergency” conditions.⁷ State and federal regulators had already determined that the Campbell plant was *not* needed to serve the utility’s customers or to ensure regional or local grid reliability.⁸

² Sarah Leach, *Activists, Officials Call for Closure of Ottawa County Coal Plant As Utility Looks To Recover Costs*, MICH. ADVANCE (Aug. 13, 2025), <https://michiganadvance.com/2025/08/13/activists-officials-call-for-closure-of-ottawa-county-coal-plant-as-utility-looks-to-recover-costs/>; Marianne Lavelle, *Trump’s Order To Keep Michigan Coal Plant Running Has Cost \$80 Million So Far*, INSIDE CLIMATE NEWS (Oct. 31, 2025), <https://insideclimatenews.org/news/31102025/michigan-campbell-coal-plant-operation-has-cost-80-million/>.

³ Leach, *supra* note 2.

⁴ See Brian Martucci, *Consumers Energy to Invest More Than \$13B in Renewables, Distribution by 2029*, UTIL. DIVE (Nov. 18, 2025), <https://www.utilitydive.com/news/consumers-energy-campbell-large-load-earnings/805778/>.

⁵ Lucas Smolcic Larson, *Tab for Keeping Michigan Coal Plant Open Under Trump Orders Grows to \$135M*, MLive (Feb. 12, 2026), <https://www.mlive.com/news/2026/02/tab-for-keeping-michigan-coal-plant-open-under-trump-orders-grows-to-135m.html>; Consumers Energy Co., Annual Report (Form 10-K) 117-118 (Dec. 30, 2025), <https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/016cee55-60d5-4eb2-b0be-b7e9b0f07c57.pdf> (discussing net costs of DOE orders); Brett Dahlberg, *Michigan Coal Plant Set to Shut Down in 8 Days Must Stay Open, Trump Administration Says*, MICH. PUB. (May 24, 2025, at 13:55 ET) <https://www.michiganpublic.org/transportation-infrastructure/2025-05-23/michigan-coal-plant-set-to-shut-down-in-8-days-must-stay-open-trump-administration-says> (discussing criticism of DOE order by leaders of the Michigan Public Service Commission); Leach, *supra* note 2 (describing costs).

⁶ See *infra* Part III (discussing litigation).

⁷ 16 U.S.C. § 824a(c)(1) (describing conditions for use of emergency authority).

⁸ Dahlberg, *supra* note 5.

But DOE nevertheless alleged that Michigan was facing emergency conditions due to insufficient regional electricity supply.⁹

The DOE order also departed significantly from the distinct roles Congress had created for federal agencies and states to regulate electricity production. Those roles have emphasized the development of market-structuring regulations by the Federal Energy Regulatory Commission (“FERC”)—an independent and relatively technocratic agency—through processes governed by the procedural and substantive constraints of administrative law.¹⁰ Congress also preserved substantial state authority over power plants within their territories.¹¹ But with electricity, as in many other realms,¹² the second Trump administration has changed the rules. The Consumers Energy order was just a starting point. More FPA Section 202(c) orders followed, with all similarly requiring aging, expensive, and in some cases inoperable coal-fired power plants (along with one dual-fuel oil and gas plant) to stay online regardless of their costs or ability to even generate electricity.¹³ Still more appear to be in the works.¹⁴

These orders are part of a broader shift. They followed a series of executive orders in which President Trump declared an “energy emergency,”¹⁵ told federal agencies to stop permitting wind and solar projects, and directed DOE to adopt new planning rules that favor coal and nuclear power and to use those new rules to force plants to stay open.¹⁶ Collectively, these executive orders represent a new vision for centralized authority over the management of the electric grid. Technocratic,

⁹ *Federal Power Act Section 202(c): Midcontinent Independent System Operator (MISO)*, *supra* note 1; Martucci, *supra* note 4.

¹⁰ Sharon B. Jacobs, *The Statutory Separation of Powers*, 129 *YALE L.J.* 378, 407-27 (2019) (discussing history, structure, and role of FERC).

¹¹ 16 U.S.C. §§ 842(a), (b)(1) (discussing state authority).

¹² For two among many possible examples, see *Justice Department Struggles as Thousands Exit—and Few Are Replaced*, *ABA J.* (Nov. 19, 2025), https://www.americanbar.org/advocacy/governmental_legislative_work/publications/washingtonletter/november-25-wl/outside-the-gao-1125wl/ (describing the loss of much of the DOJ’s workforce and the politicization of hiring); Mattathias Schwartz, Zach Montague & Ernesto Londoño, *Judges Grow Angry Over Trump Administration Violating their Orders*, *N.Y. TIMES* (Feb. 24, 2026), <https://www.nytimes.com/2026/02/23/us/politics/judges-contempt-immigration-trump.html?login=email&auth=login-email> (describing persistent disregard for judicial orders).

¹³ See Sonal Patel, *DOE Uses Emergency Powers to Freeze More Than 2 GW of Coal Retirements as Opposition Intensifies*, *POWER* (Dec. 31, 2025), <https://www.powermag.com/doe-uses-emergency-powers-to-freeze-more-than-2-gw-of-coal-retirements-as-opposition-intensifies/>; *infra* Part III (discussing DOE orders to keep coal plants open in Indiana, Colorado, and Washington); Jeffrey Tomich, *DOE Ordered Indiana Coal Plant to Run Despite Owner’s Objection*, *CLIMATEWIRE* (Apr. 17, 2026), <https://subscriber.politicopro.com/article/eenews/2026/04/17/doe-ordered-indiana-coal-plant-to-run-despite-owners-objection-cw-00877750>; Appendix (describing plants subject to Section 202(c) orders in 2025).

¹⁴ See *2025 DOE 202(c) Orders*, U.S. DEP’T OF ENERGY, <https://www.energy.gov/ceser/2025-doe-202c-orders>; Claire Brown & Brad Plumer, *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could Get Messy*, *N.Y. TIMES* (Jan. 16, 2026), <https://www.nytimes.com/2026/01/16/climate/trump-coal-plants.html>.

¹⁵ Exec. Order No. 14,156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

¹⁶ See *infra* Part III.

expert-driven decision-making is increasingly on the outs, as is the notion that economic value will be a central driver of policy choices. For instance, the orders prohibiting the J.H. Campbell plant in Michigan from retiring marked the first time the DOE had ever issued an order under Section 202(c) on its own initiative, rather than in response to a formal request by a utility, a state, or a regional grid operator.¹⁷

Though the DOE Section 202(c) orders mark a major change from recent electricity-governance practices, they might at first seem to have historical antecedents. During and after both world wars, the federal executive branch played an active role in managing existing electricity resources to support the war effort.¹⁸ Thus, one might infer that, as much as the Trump Administration's use of emergency statutory authority to override expert decision-making processes is unusual, it might still have historical support. That possible inference creates a need to place the current use of Section 202(c) orders in historical context, and this Essay supplies that context.

Part I recounts the executive branch's role in electricity governance during the first part of the twentieth century. In what until recently would have seemed like a maximalist use of federal authority, the federal government responded to the imperatives of war by building new electricity supplies and actively managing existing electricity infrastructure. But even amid the urgency of wartime, the executive branch was laying the foundation for an integrated grid managed by expert government agencies, not through direct presidential decrees. Part II describes the executive branch's involvement in electricity governance over the latter part of the twentieth century and the beginning of the twenty-first. The general theme of this era also was not assertive presidential control, but instead deference to Congressionally created regulatory and ratemaking agencies. Part III details the second Trump administration's increased reliance on never-before-used statutory emergency authorities to depart from longstanding electric grid governance. Finally, Part IV explains why this matters, focusing on both on its doctrinal significance, as well as the heavy financial and environmental costs of the current exercise of presidential authority.

I. ELECTRICITY AND EXECUTIVE POWER DURING WARTIME

There is an element of nostalgic militarism in the Trump administration's energy rhetoric.¹⁹ The administration's emphasis on conflict and its proclivity for declaring emergencies seem calibrated to recall periods of national ambition in the face of crisis, as though the perceived imperatives of acquiring Greenland and powering

¹⁷ Dahlberg, *supra* note 5; *see also* Appendix (describing events leading up to 202(c) orders issued by DOE).

¹⁸ *See infra* Part I.

¹⁹ This is in addition to the administration's militaristic rhetoric more generally. *See, e.g.*, Exec. Order No. 14,347, 90 Fed. Reg. 43893 (Sept. 10, 2025) (Trump executive order changing the name of the Department of Defense to the Department of War).

data centers are on par with opposing Nazi aggression.²⁰ The allusions might seem strained, but the President’s rhetoric does evoke a real past. During World War I and World War II, the United States really did face major challenges with electricity generation, and the federal government played an active role in responding to these challenges.²¹ But any initial appearance of similarity is largely illusory. As described below, the wartime executive branch addressed electricity-related challenges primarily through the work of legislatively authorized administrative-agency programs, not through direct presidential control. When the wars ended, the emergency measures stopped, but wartime innovations, like heightened grid integration, laid the foundations for future economic growth.

A. World War I

On the eve of the United States’ entry into World War I in 1917, electricity systems in the United States were poorly prepared to support a war. Electricity was still a relatively new technology, and though deployment was growing rapidly,²² and manufacturers increasingly relied on electricity,²³ 75% of U.S. dwellings still lacked electric power.²⁴ Because the technology for long-distance, high-voltage transmission lines had yet to emerge, electricity generation and consumption were intensely local processes.²⁵ The nation generally lacked regional, let alone national, grids, and a direct federal role in governing electricity sales was still decades away. As a result, the sudden and sharp increase in manufacturing war supplies and munitions²⁷ caused power shortages and rolling blackouts throughout the “Steel Belt,” including urban industrial centers such as Niagara Falls, Buffalo, and Pittsburgh.²⁸

²⁰ Robert Jimison, *Some Republicans Begin to Echo Trump’s Case to Acquire Greenland*, N.Y. TIMES (Jan. 20, 2026), <https://www.nytimes.com/2026/01/20/us/politics/republicans-trump-greenland.html>; Alexandra B. Klass & Dave Owen, *Allocating Electricity*, 94 GEO. WASH. L. REV. (forthcoming 2026) (discussing data centers).

²¹ See *infra* Part II.

²² U.S. DEP’T OF COMMERCE, BUREAU OF THE CENSUS, HISTORICAL STATISTICS OF THE UNITED STATES, COLONIAL TIMES TO 1970, 827 (Bicentennial Ed., 1975), 1975/compendia/hist_stats_colonial-1970/hist_stats_colonial-1970p2-chS.pdf (see Growth of Residential Table Service) [hereinafter *Electrical Census Data*].

²³ Arthur G. Woolf, *The Residential Adoption of Electricity in Early Twentieth-Century America*, 8 ENERGY J. 19, 20 (1987).

²⁴ *Electrical Census Data*, *supra* note 22.

²⁵ Woolf, *supra* note 19, at 23.

²⁷ See, e.g., COL. CHARLES KELLER, OFF. OF THE CHIEF OF ENG’RS, WAR DEP’T, DOC. NO. 1039, THE POWER SITUATION DURING THE WAR, WITH APPENDIXES CONTAINING REPORTS ON CONDITIONS IN THE SEVERAL POWER DISTRICTS (1921) [hereinafter KELLER REPORT]; Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 798–800 (2025).

²⁸ KELLER REPORT, *supra* note 27, at 3 (explaining how “[t]he tremendous industrial activity resulting from the war orders placed by the English, French, and Russian Governments, in the Buffalo-Niagara Falls territory had, in 1915, resulted in so complete an exhaustion of surplus power . . .”).

One of the federal government's responses was the creation of an entity called the "Fuel Administration."²⁹ The agency was born out of the Food and Fuel Control Act of 1917, which granted President Wilson sweeping authority "to facilitate the movement, of foods, feeds, fuel . . . to prevent, locally or generally, scarcity, monopolization, hoarding, injurious speculation, manipulations, and private controls . . . and to establish and maintain governmental control of such necessities during the war."³⁰ Much of the agency's work focused on coal consumption, but in contrast to present-day efforts, the goal was to limit consumption, not increase it. For example, it fixed coal prices to control retail consumption³² and it appointed local committees to enforce price schedules.³³ More creative efforts included "Heatless Mondays," which were weekly prohibitions against heating certain buildings,³⁴ and "Gasless Sundays," which discouraged pleasure driving of automobiles.³⁵

The Fuel Administration was one of several wartime agencies. Congress also created a Council of National Defense,³⁶ which in turn proposed the formation of a War Industries Board ("WIB").³⁷ President Wilson ultimately approved the board, and it was tasked with coordinating the purchase of supplies between the Army and the Navy (since the Department of Defense did not yet exist to facilitate such coordination).³⁸ Its initial efforts were lackluster, but the Board eventually found some success in negotiating contracts between the military and private industry, creating a model of coordination later used in the Great Depression and World War II.⁴⁰

Most of these efforts did not appear to be heavily influenced by President Wilson, and most focused on contracting for supplies and on consumption of energy resources rather than on managing the nation's still-nascent electricity-transmission infrastructure. Nevertheless, the WIB worked, initially unsuccessfully, toward the

²⁹ *Records of the U.S. Fuel Administration [USFA]*, THE U.S. NAT'L ARCHIVES AND RECORDS ADMIN., <https://www.archives.gov/research/guide-fed-records/groups/067.html#67.1>.

³⁰ Food and Fuel Control Act, Pub. L. No. 65-41, 40 Stat. 276 (1917).

³² See e.g., *Price Fixed for Lake Coal*, N.Y. TIMES, Oct. 29, 1917, at 14.

³³ *Garfield Asks Aid of Coal Consumers; Wants Them to Co-operate in Enforcing Prices Fixed by Him. To Name State Agents Seeks Voluntary Arrangements with Operators for Adjustment of Contracts*, N.Y. TIMES (Sept. 8, 1917), at 3.

³⁴ Ed Lewis, *Look Back: Heatless Mondays Began in 1918 to Conserve Fuel*, TIMES LEADER (Jan. 16, 2022), <https://www.timesleader.com/news/1534897/look-back-heatless-mondays-began-in-1918-to- conserve-fuel>.

³⁵ David Proper, *World War I Gasless Sundays Shut Down Much Travel*, THE KEENE SENTINEL (Nov. 22, 2005), https://www.keenesentinel.com/opinion/columnists/guest/world-war-i-gasless-sundays-shut-down-much-travel-by-david-proper/article_5dae9f48-fea1-5aab-b65e-c0a19f709bee.html.

³⁶ Created and funded through the 1916 Army Appropriations Act. 50 U.S.C. § 1, Editorial Notes.

³⁷ *War Purchase Board of Three Proposed*, N.Y. TIMES, July 11, 1917, at 3.

³⁸ Benjamin R. Beede, *War Industries Board*, INT'L ENCYCLOPEDIA OF THE FIRST WORLD WAR, <https://encyclopedia.1914-1918-online.net/article/war-industries-board/> (last modified Oct. 8, 2014).

⁴⁰ *Id.*

development of an interregional electrical grid. Recognizing that the United States' industrial strength was limited by the localization of electrical power, the WIB requested that Congress introduce a bill granting the President authority to (1) centralize control over existing electric infrastructure and (2) develop new sources of generation.⁴¹ During the war itself, those efforts came to naught; Congress did not pass the proposed bill.⁴² But the WIB succeeded in bringing attention to the importance of a nationwide power network, finding supporters in both industry and government.⁴³

When the federal government wound down its wartime operations, it continued to assess its wartime efforts, and the resulting study helped lay the foundations for the modern grid. In 1919, the Secretary of War tasked Colonel Charles Keller with investigating and reporting on the shortcomings of American electrical production during the war.⁴⁴ Keller focused on power shortages in areas of critical wartime production.⁴⁵ For instance, Keller described the complete exhaustion of electrical supply in the Niagara Falls district, which stymied the wartime production of steel and chemicals for nearby plants,⁴⁶ and serious output reductions in Pittsburgh, where a “congestion of war orders and manufacturing completely exhausted the power resources of the district.”⁴⁷ Keller’s report emphasized the importance of diversification of electricity supplies,⁴⁸ but his primary proposed solution was grid integration. He reasoned that while some regions struggled to meet the power demands of production, power elsewhere was held “idle” and “unused.”⁴⁹ By building “broad lines” connecting regions and allowing electricity to flow to locations where demand outstripped supply, interconnection would increase the efficiency of consumption.⁵⁰

B. The Interwar Period

After World War I, interconnection and electricity consumption continued to grow rapidly. Expansions of electrical infrastructure allowed transmission beyond the central hubs of cities.⁵¹ Electricity use shifted towards an economy-wide customer base rather than primarily powering American industry.⁵² By 1930, over 68% of dwellings were electrified.⁵³ Meanwhile, electricity provision shifted

⁴¹ EMANUEL ET AL., *POWERING THE FIGHT* 6 (2025).

⁴² H.R. 12776, 65th Congress, 2nd Sess. (Aug. 19, 1918).

⁴³ EMANUEL ET AL., *supra* note 41.

⁴⁴ *See* KELLER REPORT, *supra* note 27.

⁴⁵ *Id.* at 1.

⁴⁶ *Id.* at 2–8.

⁴⁷ *Id.* at 11.

⁴⁸ *Id.* at 20.

⁴⁹ *Id.*

⁵⁰ *Id.* at 19.

⁵¹ Sam Kalen, *Muddling Through Modern Energy Policy: The Dormant Commerce Clause and Unmasking the Illusion of an Attleboro Line*, 24 N.Y.U. ENV'T L.J. 283, 292 (2016).

⁵² *Id.* at 291.

⁵³ Woolf, *supra* note 23, at 21.

increasingly toward large, consolidated companies, leading to an enduring business and governance model involving private monopolies and governmental price regulation.⁵⁴

Much of that regulation was handled by state public utility commissions, which still regulate the retail prices charged by electric utilities.⁵⁵ But federal roles also evolved, and the interwar period saw the emergence of regulatory structures that would endure and grow through the rest of the twentieth century—and that are central to the controversies of the present day. In 1920, Congress created the Federal Power Commission (“FPC”) and granted it “the authority to regulate the construction, operation, and maintenance of nonfederal hydroelectric power generation.”⁵⁶ Congress also gave the FPC partial insulation from political control.⁵⁷

Congress would soon enhance the FPC’s authority. The continued expansion and interconnection of electrical grids, the increase in market power of privately-owned utilities, and a Supreme Court case limiting state regulation of interstate electricity sales⁵⁹ led, in 1935, to the enactment of reform legislation, including major amendments to the Federal Power Act (“FPA”).⁶⁰ The law expanded the FPC’s jurisdiction, mandated that all rates and charges for interstate wholesale electricity sales and the transmission of electricity be “just and reasonable,” and provided a mechanism to remedy rates that failed to meet this standard.⁶¹ Retail sales remained subject to state regulation, as did decisions about the siting and permitting of power plants and transmission facilities.⁶²

⁵⁴ Kalen, *supra* note 51, at 301–03.

⁵⁵ LINCOLN L. DAVIES, ALEXANDRA B. KLASS, UMA OUTKA, HARI M. OSOFSKY, JOSEPH P. TOMAIN & ELIZABETH WILSON, *ENERGY LAW AND POLICY* 378, 384–85 (4th ed. 2026) (discussing history of federal and state regulation of the electricity sector); *New York v. FERC*, 535 U.S. 1, 5–7 (2002) (same).

⁵⁶ Adam Vann, *The Legal Framework of the Federal Power Act*, LIBR. OF CONG. (Jan. 22, 2020), <https://www.congress.gov/crs-product/IF11411>.

⁵⁷ Congress specified that the FPC would have five members, who would be appointed by the President with the advice and consent of the Senate; that the members would serve fixed terms; and that no more than three members would be from the same political party. Federal Water Power Act, ch. 284, 41 Stat. 1063 (1920) (codified as amended at 15 U.S.C. ch. 12 (2012)); Marla Barnes, *Tracing the Timeline: 101 Years of the Federal Power Act*, Nat’l Hydropower Ass’n (June 7, 2021), <https://hydro.org/powerhouse/article/tracing-the-timeline-101-years-of-the-federal-power-act/> (recounting Congress’s creation of the FPC in 1920 and its decision to convert it to a five-member commission in 1930).

⁵⁹ *Pub. Utils. Comm’n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927).

⁶⁰ 16 U.S.C. § 791a. On the same day it enacted the FPA, Congress also enacted the Public Utility Holding Company Act of 1935 (PUHCA), designed to reduce the size and economic power of utility holding companies. *See*, Aneil Kovvali & Joshua C. Macey, *The Corporate Governance of Public Utilities*, 40 *Yale J. Reg.* 569, 616 (2023) (discussing PUHCA).

⁶¹ Vann, *supra* note 56.

⁶² *See* 16 U.S.C. § 824; Matthew R. Christenson & Joshua Macey, *Long Live the Federal Power Act’s Bright Line*, 134 *HARV. L. REV.* 1360, 1371–72 (2021).

The FPA gave the FPC only modest authority over interconnections,⁶³ but also included broader interconnection authority under limited circumstances. Section 202(c) provided:

During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.⁶⁴

That provision was narrow by design.⁶⁵ It was motivated by Congress's experience with severe electricity shortages during World War I.⁶⁶ Post-war investigations, including the Keller Report, had revealed that many power shortages during the war resulted from the lack of interconnection among isolated utility systems, not because the nation had insufficient generating capacity.⁶⁷ But Congress also remained reluctant to grant the FPC broad authority over electric utilities' grid interconnections.⁶⁸ Consequently, and "with the Keller report in mind," it drafted Section 202(c) as an extraordinary power.⁶⁹ A Senate committee report stated that the provision was "a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose."⁷⁰ The report also observed that natural emergencies such as droughts could lead to similar crises,⁷¹ an apparent reference to drought-fueled power shortages in California from 1918 to 1920.⁷² But the context for the provision, like its text, shows that Congress intended it as an extraordinary power for emergency use.

⁶³ Public Utility Act of 1935, ch. 687, § 202(b), 49 Stat. 803, 848 (current version at 16 U.S.C. § 824a(b)) (giving the FPC power to order "a public utility . . . to establish physical connection of its transmission facilities").

⁶⁴ Public Utility Act of 1935, ch. 687, § 202(c), 49 Stat. 803, 849 (current version at 16 U.S.C. § 824a(c)).

⁶⁵ See generally Rolsma, *supra* note 27 (recounting legislative history).

⁶⁶ S. REP. NO. 74-621, at 19 (1935).

⁶⁷ See KELLER REPORT, *supra* note 27, at 18–19.

⁶⁸ See Horace M. Gray, *The Integration of the Electric Power Industry*, 41 AM. ECON. REV. 538, 538 (1951).

⁶⁹ Rolsma, *supra* note 23, at 801.

⁷⁰ S. REP. NO. 74-621, at 49 (1935).

⁷¹ *Id.*

⁷² *Public Utility Holding Companies: Hearings on H.R. 5423 Before the H. Comm. on Interstate and Foreign Com.*, 74th Cong. 272–74 (1935) (statement of Comm'r Frank R. McNinch, Chairman, Fed. Power Comm'n).

C. World War II

Throughout the 1930s, memories of the last war and the possibility of the next one loomed over federal electricity governance. As early as 1935, the FPC published a survey—completed at President Roosevelt’s request—that assessed the nation’s existing and potential hydropower systems and addressed problems of national defense.⁷³ The report described the potential for power shortages in the eastern and midwestern industrial centers if the United States “should become involved in war,”⁷⁴ emphasized the need for increased interconnection, and imagined a larger role for the federal government in planning future electrification.⁷⁵

By the late 1930s, as events in Europe turned increasingly ominous, that focus intensified.⁷⁶ In March 1938, President Roosevelt directed the FPC and the War Department to jointly survey the nation’s wartime power capacity.⁷⁷ Roosevelt was aware of President Wilson’s struggles during World War I, and “resolved beforehand to map out a national defense power program in order to avert a shortage of electricity.”⁷⁸ The agencies concluded that wartime load would lead to a widespread energy shortage and deemed the state of the nation’s electricity landscape “so serious as to require immediate attention.”⁷⁹ The warnings proved prescient. Within weeks of Pearl Harbor, industry groups reported shortages.⁸⁰

Even before the war, there were intense disagreements about how those needs should be met. One conflict concerned whether the federal government should emphasize interconnection of electricity systems, the construction of new power plants, or both. The FPC, building on preferences dating back to the Keller Report, favored a combination. In the summer of 1938, the FPC engineering staff proposed a comprehensive plan that would serve both wartime needs and long-term national power policy through the construction of an interconnected network of high-capacity transmission lines and the expansion of hydroelectric and steam-electric power.⁸¹ The War Department opposed this approach, arguing that it was unnecessarily expensive and would divert resources from military rearmament.⁸² Instead, the War Department favored constructing additional coal-fired power

⁷³ See Fed. Power Comm’n, Power Ser. No. 1, National Power Survey Interim Report (1935).

⁷⁴ *Id.* at xi.

⁷⁵ *Id.* at 55.

⁷⁶ JULIE A. COHN, *THE GRID: BIOGRAPHY OF AN AMERICAN TECHNOLOGY* 106 (2017).

⁷⁷ Philip J. Funigiello, *Kilowatts for Defense: The New Deal and the Coming of the Second World War*, 56 J. OF AM. HIST. 604, 605 (1969).

⁷⁸ *Id.* at 604.

⁷⁹ Confidential Memorandum on Shortages of Electric Generating Capacity for War-Time Needs (July 1, 1938) (on file with Manuscript Division, Library of Congress, George W. Norris Papers, Box 2, Tray 72).

⁸⁰ *Power Needs Met, Kellogg Reports*, N.Y. TIMES, Dec. 22, 1941, at 31.

⁸¹ PHILIP J. FUNIGIELLO, *TOWARD A NATIONAL POWER POLICY: THE NEW DEAL AND THE ELECTRIC UTILITY INDUSTRY, 1933–1941* 234 (1973).

⁸² Memorandum to the National Defense Power Committee (Aug. 12, 1938) (on file with Franklin D. Roosevelt Library, Hyde Park, N.Y., Leland Olds Papers, Box 61).

plants in each industrial center.⁸³ The FPC stuck to its position. It saw no reason why its “more comprehensive program should be sacrificed because in the past the military had done a poor job of looking after its armaments.”⁸⁴ Ultimately, the FPC’s approach prevailed, with key administration figures concluding the it was better suited to meeting defense needs and more consistent with broader New Deal policy commitments.⁸⁵

A second conflict concerned who within the government should exercise wartime authority. In September 1938, President Roosevelt established the National Defense Power Committee (“NDPC”) to recommend solutions for alleviating the predicted wartime energy shortages identified by the FPC and War Department’s survey.⁸⁶ However, after significant bureaucratic conflict within the NDPC, President Roosevelt concluded that the committee structure was unworkable and turned instead to the FPC, which he viewed as staffed by technically competent administrators capable of decisive action.⁸⁹

Over the course of the war, the FPC used its FPA Section 202(c) authority twenty-two times.⁹⁰ In June 1941, the FPC found that “an emergency . . . exists in the southeastern area of the United States, resulting from a sudden increase in the demand for electric energy to meet the requirements of national defense production.”⁹¹ The Commission followed this declaration with ten separate Section 202(c) orders on the same day.⁹² Among other recommendations and mandates, these orders compelled the interconnection of Florida Power & Light Company and the Florida Public Service Company,⁹³ the construction of a 100,000-volt circuit from a Duke Power Company substation to a Carolina Aluminum Company substation,⁹⁴ and the construction of a 110,000-volt circuit interconnecting New Orleans Public Service, Inc. and Mississippi Power Company.⁹⁵ Each order recognized the state of emergency due to increased wartime demand and declared that an emergency connection of facilities or increased generation, transmission, or delivery was necessary.⁹⁶

⁸³ *Id.*

⁸⁴ FUNIGIELLO, *supra* note 81, at 234.

⁸⁵ *Id.* at 234–35.

⁸⁶ Letter from President Franklin D. Roosevelt to the Sec’y of War (Sep. 3, 1938) (on file with Nat’l Archives, Records of the Federal Energy Regulatory Commission, Record Group 138).

⁸⁹ FUNIGIELLO, *supra* note 81, at 251.

⁹⁰ Rolsma, *supra* note 27, at 803.

⁹¹ Recommendation for Curtailment of the Use of Elec. Energy in the Se. States, 2 F.P.C. 990, 990 (1941).

⁹² See Ga. Power & Light Co., 2 F.P.C. 993, 993–94 (1941); Fla. Power Corp., 2 F.P.C. 994, 994–95 (1941); Ga. Power & Light Co., 2 F.P.C. 995, 995–96 (1941); Ala. Elec. Coop., 2 F.P.C. 996, 996–97 (1941); Tenn. Valley Auth., 2 F.P.C. 997, 997–98 (1941); Carolina Aluminum Co., 2 F.P.C. 998, 998–99 (1941).

⁹³ See Fla. Power & Light Co., 2 F.P.C. 991, 991 (1941).

⁹⁴ See Duke Power Co., 2 F.P.C. 992, 992 (1941).

⁹⁵ See New Orleans Pub. Serv., Inc., 2 F.P.C. 992, 992–93 (1941).

⁹⁶ See, e.g., Fla. Power & Light Co., 2 F.P.C. 991, 991 (1941); Duke Power Co., 2 F.P.C. 992, 992 (1941).

Beyond ordering individual interconnections, the FPC played a key role in creating “power pools,” which were arrangements through which private utilities would share power. These pools changed the ways utilities operated, for many of them were unaccustomed to treating power grids as shared resources or working with their competitors, and some had carefully avoided interstate sales to prevent the federal regulation.⁹⁷ Soon, major regions of the country were functioning as part of coordinated electricity networks with interties between regions, which meant that power shortages in some areas could be met with electricity from others with excess supply. Later historical accounts have treated these power pools as one of the most important innovations of the United States’ World War II energy policies.⁹⁸

In multiple ways, these World War II innovations helped sow the seeds for a more national grid and the complex electricity markets of the present day. As interconnected systems grew larger and remained coupled nearly full-time during the war, the traditional challenges of managing frequency and load became more intricate and demanding, leading to technological innovations that became industry standards.⁹⁹ Institutional capacity also grew, as both federal agencies and utilities had to learn how to work across institutional boundaries. More generally, the United States moved quickly away from the prewar world, in which electricity distribution often involved poorly connected or disconnected private fiefs, and toward the efficiencies of an interconnected economy and grid.

II. FEDERAL GRID GOVERNANCE IN THE MODERN ERA

As the prior Part illustrates, the federal government’s wartime role in grid management was assertive. But that role also emphasized grid integration and relied on agencies—particularly the FPC—rather than direct presidential control. That emphasis on agencies fits with broader themes of this era, for the early part of the twentieth century saw much of the emergence of the modern administrative state.¹⁰⁰ Regulatory agencies increasingly exercised congressionally delegated authority, often with only modest executive oversight, across a wide range of economic spheres.¹⁰¹ Electricity, even during wartime, was no exception.

Until recently, that trend continued. This Part surveys the federal electric grid management systems that continued to emerge and evolve from the postwar period through the present, and that trace their roots to the innovations of the interwar period and World War II. These systems and their history are complicated, and no generalization holds entirely true across multiple agencies or over such a long span of time. Nevertheless, throughout this period, management of the nation’s electric grid, though heavily influenced by the federal government, was generally not a

⁹⁷ See COHN, *supra* note 76, at 109.

⁹⁸ *Id.* at 117, 120.

⁹⁹ *Id.* at 114–117.

¹⁰⁰ See generally CASS SUNSTEIN, *AFTER THE RIGHTS REVOLUTION* (1990) (chronicling the twentieth-century expansion of administrative governance).

¹⁰¹ See *id.* at 18–24.

sphere of substantial *presidential* influence either through executive orders or DOE actions. Instead, the dominant actor became FERC, an independent agency¹⁰² that operated under legislative delegations conferring sweeping discretion,¹⁰³ whose decision-making was steeped in technical expertise,¹⁰⁴ and that showed stable policy commitments even across presidential administrations.¹⁰⁵

A. *The Federal Energy Regulatory Commission: The Electric Grid Regulator*

This section picks up where Part I left off and describes the evolution of FERC regulation through the early twenty-first century. After World War II, technologies and challenges evolved, federal regulation of the energy sector continued to develop, and new agencies emerged. For instance, in the 1940s, Congress created the Atomic Energy Commission (“AEC”) to regulate the commercial use of nuclear power.¹⁰⁶ It also created new authorities within the executive branch, partly in response to the energy crisis following the 1973 Arab Oil Embargo.¹⁰⁷ In 1977, Congress enacted the Department of Energy Organization Act (“DOE Act”), which split up the FPC’s responsibilities.¹⁰⁸ Congress gave some federal energy activities to the newly created DOE, described in more detail in Section II.B, with a Secretary appointed by the President and subject to Senate confirmation.¹⁰⁹ And it assigned the FPC’s responsibility for electricity-grid regulation and ratemaking to the newly created FERC.¹¹⁰

Subsequent legislation, including the Energy Policy Act of 1992,¹¹² the Energy Policy Act of 2005,¹¹³ and the Infrastructure Investment and Jobs Act of 2021,¹¹⁴ among others, expanded FERC’s regulatory authority over the electricity sector.

¹⁰² See Kirti Datla & Richard L. Revesz, *Deconstructing Administrative Agencies (and Executive Agencies)*, 98 CORNELL L. REV. 769, 825 (2013).

¹⁰³ See Jodi L. Short, *In Search of the Public Interest*, 40 YALE J. REG. 759, 804 (2023).

¹⁰⁴ See Sharon Jacobs, *The Challenges of Participatory Administration*, 58 UC DAVIS L. REV. 323, 340-45 (2024) (describing the technical and sometimes opaque nature of electricity regulation).

¹⁰⁵ See Francisco “A.J.” Camacho, *Trump Wants Agencies on a Short Leash. What Does that Mean for FERC?*, E&E NEWS (Dec. 10, 2024), <https://www.eenews.net/articles/trump-wants-agencies-on-a-short-leash-what-does-that-mean-for-ferc/>.

¹⁰⁶ Atomic Energy Act of 1946, Pub. L. No. 79-585, 60 Stat. 755 (1946).

¹⁰⁷ For discussions of how the Arab Oil Embargo transformed U.S. domestic energy policy, see generally DANIEL YERGIN, *THE PRIZE: THE EPIC QUESTION FOR OIL, MONEY & POWER* 644-47 (1991); JAY HAKES, *ENERGY CRISES: NIXON, FORD, CARTER, AND HARD CHOICES IN THE 1970s* 200-201, 217, 224-27, 342-42 (2021).

¹⁰⁸ Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (1977) (codified at 42 U.S.C. §§ 7101–352); see also *A Brief History of the Department of Energy*, DEP’T OF ENERGY, <https://www.energy.gov/lm/brief-history-department-energy>.

¹⁰⁹ Pub. L. 95-91, 91 Stat. 565 §§ 201–02 (codified at 42 U.S.C. §§ 7131–7132).

¹¹⁰ Unlike DOE, FERC is a five-member commission supported by a career staff. Each member serves a five-year term, terms are staggered, no more than three commissioners are from the same political party, and each commissioner is appointed by the President and must be confirmed by the U.S. Senate. *Id.* § 401(b)(1) (codified at 42 U.S.C. § 7171).

¹¹² Energy Policy Act of 1992, Pub. L. No. 102-486, 102 Stat. 2776.

¹¹³ Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

¹¹⁴ Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).

That authority now includes responsibilities to protect power-grid reliability through creation of mandatory reliability standards, monitoring and investigating energy markets, and penalizing market participants that violate market rules.¹¹⁵

FERC has done a lot with that authority. The central story of electricity regulation over the last fifty years has been a movement away from systems built around private monopolies and governmental price regulation, and toward increased market competition.¹¹⁶ In the 1980s and 1990s, FERC adopted market-based rates for independent power producers,¹¹⁷ enacted regulations designed to allow utilities to sell power outside their service areas, and required open access transmission, which means that utilities cannot engage in price discrimination against independent power producers or purchasers that wish to use the utilities' power lines.¹¹⁸ And it encouraged the formation of regional transmission organizations ("RTOs"), which are non-profit, private entities that utilities use to jointly manage the shared grid and oversee wholesale auctions for energy and other grid services.¹¹⁹

FERC, together with RTOs and states, also helps maintain "resource adequacy," which means ensuring that there is adequate electricity generation to meet bulk power system needs and avoid brownouts and blackouts.¹²⁰ While the FPA left jurisdiction over energy generation plants primarily to states, many states have directed or permitted their utilities to join RTOs, which, subject to FERC review and oversight, impose resource-adequacy requirements on member utilities.¹²¹ Utilities fulfill those obligations through long-term planning and technical analysis, which they complete in cooperation with states, RTOs, and FERC.¹²² Likewise, the North American Electric Reliability Corporation ("NERC"), with authorization

¹¹⁵ See *What FERC Does*, FED. ENERGY REG. COMM'N, <https://www.ferc.gov/what-ferc-does>; PAUL W. PARFOMAK, CONG. RSCH. SERV., R48349, *THE FEDERAL ENERGY REGULATORY COMMISSION (FERC): AUTHORITIES AND MEMBERSHIP* (2026); Sharon Jacobs & Ari Peskoe, *Energy Emergencies vs. Manufactured Crises: The Limits of Federal Authority to Disrupt Power Markets*, 2019 HARV. L. SCH. ENV'T & ENERGY L. PROGRAM 6-7 (2019) (discussing how the Energy Policy Act of 2005 authorized FERC to regulate grid reliability); see also Energy Policy Act of 2005, 16 U.S.C. § 825(f), (j) (authorizing FERC to conduct investigations into FPA violations); *id.* § 825o-1 (granting FERC authority to assess penalties of up to \$1 million per day for each FPA violation).

¹¹⁶ See *FERC v. Electric Power Supply Ass'n*, 577 U.S. 260, 267 (2016) (describing FERC's evolving role); see generally Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 ENV'T L. 435 (2002) (describing these changes).

¹¹⁷ See *Morgan Stanley Capital Group, Inc.*, 554 U.S. at 535 (describing market-based rates, among other regulatory reforms).

¹¹⁸ See *New York v. FERC*, 535 U.S. 1, 5 (2002).

¹¹⁹ See *FERC v. Electric Power Supply Ass'n*, 577 U.S. 260, 267-68 (2016); see also *Energy Markets*, FED. ENERGY REG. COMM'N, <https://www.ferc.gov/opp/energy-markets>.

¹²⁰ *Reliability Explainer*, FED. ENERGY REGUL. COMM'N, <https://www.ferc.gov/reliability-explainer>; *Resource Adequacy for a Clean Energy Grid*, STINSON (Nov. 2021), https://acore.org/wp-content/uploads/2021/11/RA-for-a-Clean-Energy-Grid_Legal-Analysis.pdf; Joshua C. Macey, Shelley Welton & Hannah Wiseman, *Grid Reliability in the Electric Era*, 41 YALE J. REG. 164, 195-96 (2024) (discussing resource adequacy).

¹²¹ See *Resource Adequacy for a Clean Energy Grid*, *supra* note 120.

¹²² See Macey et al., *supra* note 120, at 194-96.

from Congress in the Energy Policy Act of 2005, sets mandatory standards for grid reliability, subject to FERC review and oversight.¹²³ Notably, Congress created no role for DOE in addressing long-term resource adequacy or grid reliability.

To what extent these innovations have been successful is one of the central questions of energy law. The debates are broad, rich, and variegated, with scholars arguing whether FERC's reforms have been sufficiently democratic;¹²⁴ adequately sensitive to the needs of disadvantaged communities and to emerging concepts of energy justice;¹²⁵ aggressive enough in pursuit of decarbonization;¹²⁶ and overly solicitous of the roles of traditional vertically integrated private utilities,¹²⁷ among many other subjects.

But amid the many debates, some things are relatively clear. Most importantly, these reforms have opened up electricity markets to many new participants, who have brought increased competition and created downward pressure on prices.¹²⁸ These reforms also have allowed the market entry of new types of energy generation, including wind and solar.¹²⁹ One other feature of FERC's transformation of grid regulation also bears mentioning: presidents didn't have much to do with it. No presidential proclamation spurred FERC's orders creating wholesale electricity markets, RTOs, or approaches to resource adequacy. Nor did the overall trajectory of agency policy shift dramatically from administration to administration. Instead, the agency's direction remained consistent over long periods of time, and its decision-making was largely technocratic, with elected politicians exercising influence through legislation, not presidential directives.¹³⁰

B. The Department of Energy: Electricity Innovator, Research Partner, Funder, and Emergency Responder

In contrast to the FPC and FERC, DOE's origin story comes from the Manhattan Project, the highly-classified effort by the U.S. War Department to work intensely with the scientific community to create the world's first nuclear

¹²³ *Id.* at 205.

¹²⁴ *See, e.g.,* Jacobs, *supra* note 104, at 345–49, 384–87 (analyzing FERC's efforts to promote democratic participation).

¹²⁵ *E.g.* Shalanda H. Baker, *Anti-Resilience: A Roadmap for Transformational Justice within the Energy System*, 54 HARV. C.R.–C.L. L. REV. 1, 36–37 (2019) (arguing that FERC has insufficiently addressed social and racial justice concerns).

¹²⁶ *E.g.* Shelley Welton, *Electricity Markets and the Social Project of Decarbonization* 118 COLUM. L. REV. 1067, 1112–13 (2018) (discussing limitations associated with RTO decarbonization efforts requiring FERC approval).

¹²⁷ *See, e.g.,* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 45–46, 61 (2021).

¹²⁸ *See generally*, FED. ENERGY REGUL. COMM'N, 2024 STATE OF THE MARKETS REPORT (2025) (noting that wholesale prices are declining even as grid additions are dominated by solar, natural gas, wind, and battery storage).

¹²⁹ *See id.* at 28–32.

¹³⁰ *See* Jacobs, *supra* note 10, at 416–18.

weapon.¹³¹ This initiative required “large, multi-purpose facilities that became the nation’s first national laboratories,” which today are housed within the Office of Science at DOE.¹³² For decades, different offices within DOE have supported many aspects of energy research, development, demonstration, and deployment—including in the electricity sector—through billions of dollars in grants, loans, and other funding.¹³³

DOE also acts as a first responder for grid emergencies. But until recently, DOE had understood its emergency-response authority to be limited to short-term responses to genuine emergencies, and it had exercised its powers—mostly—accordingly. As discussed in Part I, in 1935, Congress authorized the FPC to issue temporary orders to require grid-stabilizing actions by private-sector actors in times of war or emergency in Section 202(c) of the FPA.¹³⁴ Later, when Congress enacted the Department of Energy Organization Act of 1977 (discussed in more detail in Section II.A) and divided executive branch electricity-related authority among multiple new federal agencies, it transferred the FPC’s Section 202(c) authority to DOE.¹³⁵

The FPC and, later, DOE, have exercised 202(c) emergency authority dozens of times, but until recently, both agencies hewed closely to the statutory language limiting its use to wartime conditions and sudden emergencies.¹³⁶ As discussed in Part I, the FPC invoked this authority during World War II, primarily to compel grid integration.¹³⁷ The FPC also issued orders during and after the Korean War, but issued just seven 202(c) orders from 1944 until DOE assumed authority in 1977.¹³⁸ And when a utility challenged the FPC’s decision *not* to use 202(c) to address the Arab Oil Embargo in the early 1970s, the D.C. Circuit Court of Appeals sided with the FPC, finding that dependence on foreign oil was a “continuing” emergency and

¹³¹ *A Brief History of the Department of Energy*, U.S. DEP’T OF ENERGY, <https://www.energy.gov/lm/brief-history-department-energy>.

¹³² *History*, U.S. Dep’t of Energy, <https://www.energy.gov/science/history>.

¹³³ Zahava Urecki & Tanya Das, *The Department of Energy’s Role in Fostering Innovation to Meet America’s Energy Needs*, BIPARTISAN POL’Y CTR. (Oct. 2, 2025), <https://bipartisanpolicy.org/issue-brief/the-department-of-energys-role-in-fostering-innovation-to-meet-americas-energy-needs/>.

¹³⁴ 16 U.S.C. § 824a(c).

¹³⁵ See Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (1977) (codified at 42 U.S.C. §§ 7101–352); *A Brief History of the Department of Energy*, DEP’T OF ENERGY, <https://www.energy.gov/lm/brief-history-department-energy>.

¹³⁶ See *DOE’s Use of Federal Power Act Emergency Authorities*, U.S. DEP’T OF ENERGY, <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>.

¹³⁷ See *supra* Section I.C; ASHLEY J. LAWSON, CONG. RSCH. SERV., IF12991, FEDERAL POWER ACT: THE DEPARTMENT OF ENERGY’S EMERGENCY AUTHORITY 2 (2026), <https://www.congress.gov/crs-product/IF12991>; see also Rolsma, *supra* note 27, at tbl. 2 (detailing Section 202(c) orders); Appendix (same).

¹³⁸ Rolsma, *supra* note 27, at 803-04; Appendix.

that 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances”¹³⁹

Until recently, DOE itself understood that authority to be highly cabined. In 1981, DOE issued regulations defining an “emergency” for purposes of Section 202(c), and those regulations emphasized the agency’s intent that its emergency authority should not be a substitute for long-term utility planning.¹⁴⁰ The regulations also state that “while a utility may rely on these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.”¹⁴¹ Those regulations remain in place, and in accordance with them, DOE went twenty years before issuing its first 202(c) order.

Around 2000, DOE’s practices began to change, but initially only modestly. In 2000, DOE began issuing orders to address (1) grid failures, like the 2003 Northeast blackout and the 2001 California electricity crisis, and (2) weather-related emergencies such as hurricanes, heat waves, and cold waves.¹⁴² The duration of these orders almost always ranged from a few hours to less than ninety days.¹⁴³ More importantly, until DOE’s orders preventing the retirement of the J.H. Campbell plant in Michigan, DOE had never issued an emergency order on its own initiative. Instead, it had acted only in response to a formal request by the utility, the state, or the regional grid operator.¹⁴⁴ Likewise, it had never pointed to long-

¹³⁹ *Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); Rolsma, *supra* note 27, at 812 (discussing case).

¹⁴⁰ The regulations defined “emergency” as

an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected “entity” to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. . .

10 C.F.R. § 205.371 (“Definition of emergency”); *see also* U.S. Dep’t of Energy, Final Rule, Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Storage of Electric Power, 46 Fed. Reg. 39984, 39985-86 (Aug. 6, 1981), https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

¹⁴¹ U.S. Dep’t of Energy, Final Rule, *supra* note 140, at 39985.

¹⁴² *See* Rolsma, *supra* note 23, at 805-06, 839-42; LAWSON, *supra* note 137, at Tbl. 1.

¹⁴³ LAWSON, *supra* note 137, at 2-3; *see also* Rolsma, *supra* note 27, at 819–20, 838-42 & tbl. 1; Jacobs & Peskoe, *supra* note 115, at 1, 12.

¹⁴⁴ *See* Kenneth W. Irvin et al., *Department of Energy Blocks Shutdown of Coal-Fired Power Plant and Oil- and Gas-Fired Generator Units With Federal Emergency Orders*, SIDLEY (June 13, 2025), <https://environmentalhealthsafetybrief.sidley.com/2025/06/13/departments-of-energy-blocks-shutdown-of-coal-fired-power-plant-and-oil-and-gas-fired-generator-units-with-federal-emergency-orders/> (“[U]nlike other Section 202(c) orders, the Campbell Order was issued by the DOE on its own initiative—not in response to a power plant owner, transmission provider, or grid operator application”); LAWSON, *supra* note 137, at 6 (same). For a table including all section 202(c) orders to date, *see* Appendix.

term resource adequacy concerns as a justification to use its Section 202(c) authority.¹⁴⁵

III. THE TRUMP II TRANSFORMATION

Whatever stability federal electricity governance may have enjoyed has come to an end. This Part describes the executive orders and implementation actions that have inserted President Trump’s self-described “energy dominance”¹⁴⁶ agenda into aspects of electric grid governance that Congress placed primarily in the FPC’s, and then FERC’s, control since before World War II.

President Trump’s pursuit of what he has termed “energy dominance” began in his first term, with policies designed to promote fossil fuels, particularly coal, and to discourage the development of renewable energy, particularly wind.¹⁴⁷ That agenda mostly failed, as the relatively lower costs of renewable power and natural gas meant that renewable generation and gas continued to grow and coal continued to decline.¹⁴⁸ But upon taking office again in 2025, President Trump revived these efforts, this time with an entirely new level of vigor.

On his first day in office, President Trump declared a “national energy emergency,” citing his authority under the National Emergencies Act of 1976 (“NEA”).¹⁴⁹ The order declared that the nation had inadequate energy to meet its needs and directed the heads of federal executive departments and agencies to “identify and exercise any lawful emergency authorities available to them” to facilitate the development and use of domestic energy resources.¹⁵⁰ Other executive orders early in the second Trump administration began laying the groundwork for DOE to take control of the electric grid. In April 2025, an order entitled “Strengthening the Reliability and Security of the United States Electric Grid”¹⁵¹ stated that DOE should conduct its own electric grid resource adequacy analysis and, “to the maximum extent permitted by law, streamline, systemize, and expedite” its procedures for issuing orders under Section 202(c) of the FPA.¹⁵²

In many ways, these directives broke with the past. As discussed in Part II, Congress expressly reserved authority for states to address resource adequacy and

¹⁴⁵ See, e.g., DEP’T OF ENERGY, ORDER NO. 202-25-7 (Aug. 25, 2025), <https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf>, (citing evidence of “a potential longer term resource adequacy emergency in MISO” to justify continued additional dispatch of the Campbell Plant).

¹⁴⁶ See, e.g., Establishing the National Energy Dominance Council, THE WHITE HOUSE, Feb. 14, 2025, <https://www.whitehouse.gov/presidential-actions/2025/02/establishing-the-national-energy-dominance-council/>.

¹⁴⁷ Lincoln L. Davies, Kiersten Rule Davies & Kathryn Glenn Speckart, *Trump Energy Policy 2.0*, 71 FOUND. FOR NAT. RES. & ENERGY L. INST. 2-1 (2025).

¹⁴⁸ Mickey Francis, *U.S. Renewable Energy Consumption Surpasses Coal for the First Time in Over 130 Years*, U.S. ENERGY INFO. ADMIN. (May 28, 2020), <https://www.eia.gov/todayinenergy/detail.php?id=43895>.

¹⁴⁹ Exec. Order No. 14,156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

¹⁵⁰ *Id.* at 8434.

¹⁵¹ Exec Order No. 14,262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).

¹⁵² *Id.*

delegated authority to FERC and FERC-regulated regional entities to ensure grid reliability.¹⁵³ With no change in the governing statutory law, the April 2025 electric grid executive order reassigned a dominant role for both authorities to DOE. And nothing in the executive order required or suggested that DOE should or could consult with FERC, RTOs, NERC, or states in conducting its analysis.

DOE wasted no time working to implement these mandates directing it to take control of the electric grid. Among other things, DOE began issuing a barrage of Section 202(c) orders.¹⁵⁴ All of the orders issued in 2025 directed aging and, in some cases, inoperable, coal or oil plants to be made available for dispatch beyond their scheduled retirement dates.¹⁵⁵ Notably, during the first Trump administration, DOE had considered using its Section 202(c) emergency authority to prevent utilities from retiring uneconomic coal and nuclear plants, but the agency was concerned about its legal authority to do so.¹⁵⁶ By 2025, DOE had shed those concerns.

The first of those orders, as discussed in the Introduction, involved the J.H. Campbell coal plant in Michigan.¹⁵⁷ Significantly, neither the plant owner nor the regional grid operator—the Midcontinent Independent System Operator (“MISO”)—had sought DOE assistance or expressed any concern about the plant’s closure.¹⁵⁸ Consumers Energy had already purchased a gas plant and taken other actions to make up for any reduction in generation capacity arising from the plant closure.¹⁵⁹ It also had received approval for its transition plan from the state and from federal grid reliability regulators.¹⁶⁰ In fact, the utility’s transition plan to cleaner and lower-cost energy sources—a plan that state regulators had approved—was expected to save the utility’s customers \$600 million over the next twenty years.¹⁶¹ And even after DOE issued its order, MISO affirmed that it had sufficient energy supplies in the region for the next year.¹⁶²

¹⁵³ See *supra* Part II.

¹⁵⁴ See *2025 DOE 202(c) Orders*, *supra* note 14; Appendix.

¹⁵⁵ See *2025 DOE 202(c) Orders*, *supra* note 14.

¹⁵⁶ Jacobs & Peskoe, *supra* note 115, at 21–25; Jeff Horwitz, Michael Biesecker & Matthew Daly, *Despite Earlier Assurance, Trump Denies Coal a Lifeline*, THE CHRISTIAN SCIENCE MONITOR (Aug. 22, 2017), <https://www.csmonitor.com/USA/2017/0822/Despite-earlier-assurance-Trump-denies-coal-a-lifeline>;

¹⁵⁷ Dep’t of Energy, No. 202-25-3, Midcontinent Independent System Operator (MISO) 202(c) Order 1 (2025) <https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso>.

¹⁵⁸ Dahlberg, *supra* note 5.

¹⁵⁹ MPSC Approves Consumers Energy Integrated Resource Plan Settlement Agreement, Takes Additional Steps to Boost Electricity Capacity, MICH. PUB. SERV. COMM’N (June 23, 2022), https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp_takes-steps-improve-capacity; Consumers Energy Co., *supra* note 5, at 35.

¹⁶⁰ Leach, *supra* note 2.

¹⁶¹ Lavelle, *supra* note 2.

¹⁶² Pet. for Review, Michigan v. Dep’t of Energy, No. 25-1159 (D.C. Cir. July 24, 2025), at 18-21, 27-32 (citing MISO actions and auction results).

Beyond erasing those savings, the order created new costs for Consumers Energy and for Michigan consumers. Based on the utility's SEC filings, between the issuance of the first DOE order on May 23, 2025, and December 31, 2025, Consumers Energy had incurred losses of \$135 million—the difference between the cost to continue to keep the plant online and the power-sale revenues during that time period.¹⁶³ Someone—most likely consumers—will need to pay for those losses.¹⁶⁴

The DOE's order prompted legal challenges from states, environmental advocacy groups, and other stakeholders. One action—brought by Michigan, other states in the MISO region, and environmental advocacy groups in the U.S. Court of Appeals for the D.C. Circuit—challenged the DOE's orders arguing, among other things, that there were no conditions that justified DOE's exercise of emergency authority under FPA Section 202(c) and that the orders were unlawful.¹⁶⁵

If the Campbell plant order was just a one-off event, it still would be concerning. Even that one order's costs are huge, not to mention the adverse local health and environmental impacts of continuing to operate the plant.¹⁶⁶ But instead, the Campbell order was the beginning of a pattern. Between May 2025 and March 2026, DOE issued multiple Section 202(c) orders designed to delay the closure of coal-fired power plants.¹⁶⁷ These included: (1) orders requiring a 52-year-old plant in Washington State to keep its last coal-fired boiler online despite longstanding plans to retire it and then convert the plant to run on natural gas;¹⁶⁸ orders requiring a coal plant in Colorado, which was inoperable and set to close in two days at the time of the order, to instead be made available for dispatch;¹⁶⁹ and orders requiring a 60-year-old coal unit in Indiana to remain available for dispatch beyond its retirement date, despite pleas from its owner that the plant would not be able to operate without tens of millions of dollars of unplanned ratepayer costs for

¹⁶³ Larson, *supra* note 5; Consumers Energy Co., *supra* note 5.

¹⁶⁴ Consumers Energy Co., *supra* note 5, at 117-118 (describing allocation of Campbell costs to customers); Lavelle, *supra* note 2.

¹⁶⁵ See Initial Opening Brief of the States of Illinois, Michigan, and Minnesota, Michigan v. U.S. Dep't of Energy, No. 25-1159 at 22 (Consolidated with 25-1160 and 25-1162) (D.C. Cir. Dec. 19, 2025).

¹⁶⁶ Teresa Homsy & Alexander Rabin, Opinion, *Keeping Coal Plant Online Isn't Just Costly, It Risks Michiganders' Health*, BRIDGE MI. (Nov. 14, 2025), <https://bridgemi.com/guest-commentary/opinion-keeping-coal-plant-online-isnt-just-costly-it-risks-michiganders-health/>; Ariel Wittenberg, *Pollution from Coal Plants Was Dropping. Then Came Trump and AI*, E&E NEWS (Nov. 24, 2025), <https://www.eenews.net/articles/ai-gives-coal-plants-a-lifeline-as-trump-makes-them-dirtier/>.

¹⁶⁷ *2025 DOE 202(c) Orders*, *supra* note 14; Appendix.

¹⁶⁸ Ethan Howland, *DOE Orders 730-MW TransAlta Coal Plant in Washington to Keep Running*, UTIL. DIVE (Dec. 17, 2025), <https://www.utilitydive.com/news/doe-transalta-centralia-emergency-order/808123/>.

¹⁶⁹ Ethan Howland, *DOE Orders 446-MW Colorado Coal Unit to Keep Running*, UTIL. DIVE (Jan. 6, 2026), <https://www.utilitydive.com/news/doe-colorado-coal-craig-tristate/808849/>; Brown & Plumer, *supra* note 14.

maintenance and upgrades.¹⁷⁰ Owners of the coal plants, states, and environmental groups have responded with legal challenges.¹⁷¹ Nevertheless, utilities in other states have reported that they expect to receive similar emergency orders.¹⁷² Indeed, DOE Secretary Chris Wright declared, at a White House event in January 2026, that he planned to use DOE’s Section 202(c) authority to prevent as many coal plant retirements as possible over the next three years.¹⁷³

As with the Campbell plant order, none of the subsequent DOE orders were issued in response to a request by the utilities, grid operators, or states. None of the orders resolve the issue of who beyond the utilities’ own ratepayers will bear the costs of maintaining these plants or the costs of the replacement electricity resources utilities had already procured in anticipation of the plants’ imminent closures.¹⁷⁴

Again, all of this was a marked break from the past. The bar graphs below show the Trump administration’s significant departure in the use of Section 202(c) orders from Section 202(c)’s historical use. The key point of the charts is simple: orders preventing specific plants from retiring were frequent in 2025 and 2026 but have no historical precedent.

¹⁷⁰ Benjamin Storrow & Hannah Northey, *DOE Orders 2 Indiana Coal Plants to Continue Operating*, GREENWIRE (Dec. 24, 2025), <https://www.eenews.net/articles/doe-orders-2-indiana-coal-plants-to-continue-operating/>; Tomich, *supra* note 13.

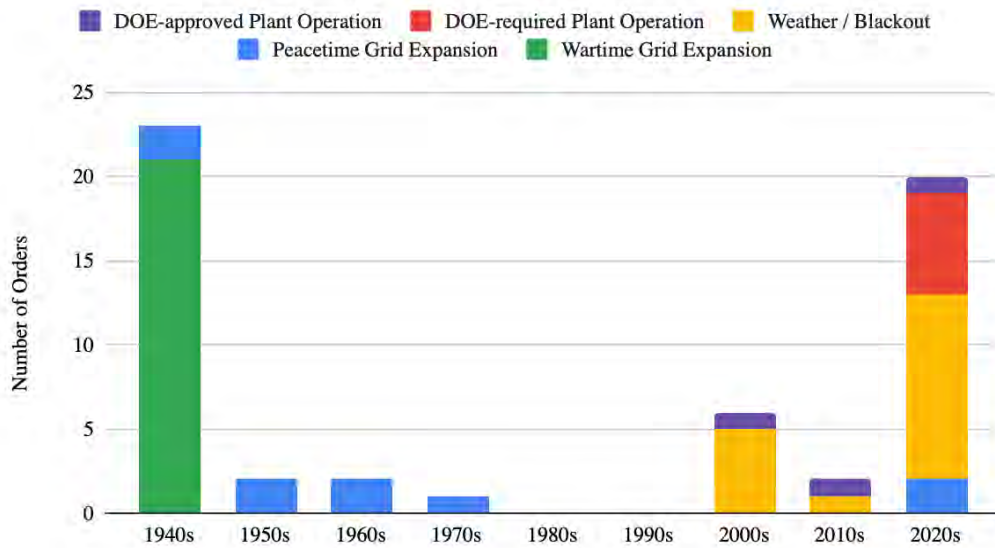
¹⁷¹ See, e.g., Ethan Howland, *Coal Plant DOE Ordered to Stay Online Unlikely to Run Given “Flush” Power Supplies: CEO*, UTIL. DIVE (Mar. 4, 2026), <https://www.utilitydive.com/news/washington-earthjustice-sue-doe-centralia-emergency-order-transalta/813754/> (describing litigation over Washington coal plant); Sam Brasch, *The Owners Want to Close This Colorado Coal Plant. The Trump Administration Says No*, NPR (Feb. 23, 2026), <https://www.npr.org/2026/02/23/g-s1-110980/trump-coal-energy-colorado> (describing litigation over Colorado plant).

¹⁷² Benjamin Storrow, *DOE Orders Washington Coal Plant to Stay Open*, CLIMATEWIRE (Dec. 17, 2025), <https://www.eenews.net/articles/doe-orders-washington-state-coal-plant-to-stay-open/>.

¹⁷³ Brown & Plumer, *supra* note 14.

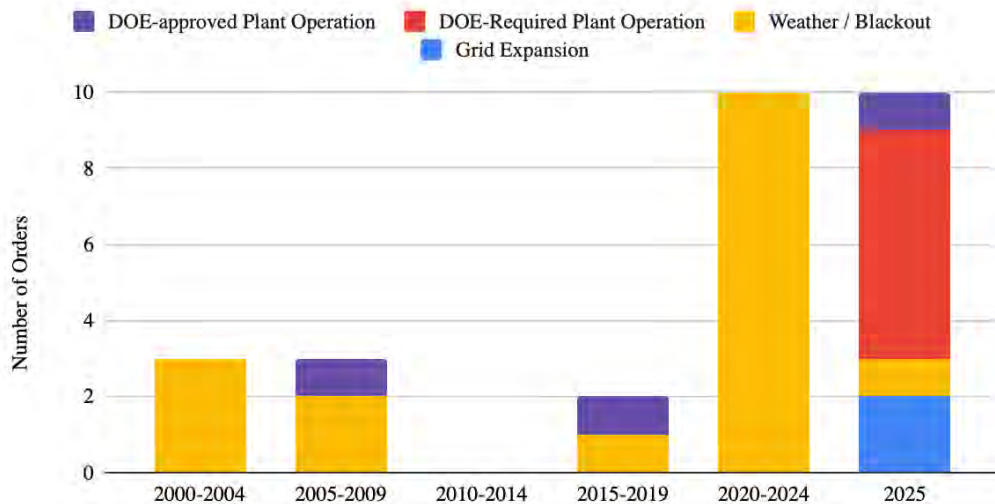
¹⁷⁴ Howland, *DOE Orders 730-MW TransAlta Coal Plant in Washington to Keep Running*, *supra* note 168; Howland, *DOE Orders 446-MW Colorado Coal Unit to Keep Running*, *supra* note 169.

FPA 202(c) Orders by Decade and Type



FPA 202(c) Orders by Type

2000-2025



IV. THE PRESIDENT AND THE POWER GRID

The prior Part described the sharp discontinuity between the second Trump administration’s electric grid policies and those of previous administrations. This Part explains two reasons why this discontinuity matters. The first reason relates to important doctrinal questions regarding statutory interpretation and presidential use of emergency authority. The second reason is practical. The grid governance approaches from which the second Trump administration has departed, while far from perfect, gave the United States electricity systems that were strong, evolving,

and improving.¹⁷⁵ Abandoning the lessons of that experience does not bode well for the future of the grid.

A. Presidential Power and Statutory Interpretation

The DOE Section 202(c) orders raise significant questions of statutory interpretation. For instance, since 2022, the Supreme Court has used the major questions doctrine to rein in executive branch agency actions where the perceived absence of a clear statement from Congress raises questions about the “history and breadth of the authority” the agency asserts or where the action is of major “economic and political significance.”¹⁷⁶ In 2026, the Court confirmed that statutes delegating emergency authority to the executive branch are not immune from scrutiny under the major questions doctrine.¹⁷⁷ Relatedly, the Court has indicated there are red flags when agencies move outside what the Justices perceive to be those agencies’ traditional roles. As Justice Barrett has put it, “[a]nother telltale sign that an agency may have transgressed its statutory authority is when it regulates outside its wheelhouse.”¹⁷⁸

The DOE Section 202(c) orders raise each of these concerns. It would be an understatement to say that Section 202(c) does not provide clear authority to order the indefinite operation of power plants in circumstances where the electric grid is operating normally and no responsible party has requested DOE intervention.¹⁷⁹ While each individual order might not have major economic or political significance, at least outside the specific grid area the affected power plant serves, the collective goal is clearly the kind of reworking of electricity-generation systems that the Court already has treated as raising major questions.¹⁸⁰ And most strikingly, the orders move DOE outside its traditional role; for decades, project-specific decisions about modes of electricity generation have been left to state governments and private ordering within a grid governance framework overseen by FERC.¹⁸¹ Indeed, outside the narrow and temporally limited context of wartime and short-term, unexpected emergencies, the federal government has not been in the business of directly ordering particular power plants under private ownership to open or

¹⁷⁵ See *supra* Part II (describing FERC actions).

¹⁷⁶ See *West Virginia v. EPA*, 597 U.S. 697, 723–24 (2022).

¹⁷⁷ See *Learning Resources v. Trump*, 607 U.S. ___, 2026 WL 477534 at *9 (U.S. Feb. 20, 2026).

¹⁷⁸ *Nebraska v. Biden*, 600 U.S. 477, 518 (2023) (Barrett, J., concurring).

¹⁷⁹ See 16 U.S.C. § 824a(c) (allowing orders only in response to an “emergency”).

¹⁸⁰ See *West Virginia*, 597 U.S. at 728–29 (arguing that choices about the amount of coal-fired power on electricity grids are major questions). In fact, the impact of the Trump administration’s Section 202(c) orders might be much greater than that of the Clean Power Plan, for the Clean Power Plan aligned with market trends, while the 202(c) orders attempt to fight those trends. See *id.* at 755 (Kagan, J. dissenting) (“[T]he Clean Power Plan never went into effect. The ensuing years, though, proved the Plan’s moderation. Market forces alone caused the power industry to meet the Plan’s nationwide emissions target—through exactly the kinds of generation shifting the Plan contemplated.”).

¹⁸¹ See *supra* Part II (describing state authority over power plants).

close.¹⁸² In raising these concerns, we do not endorse the major questions doctrine, which has been subject to extensive and persuasive scholarly criticism.¹⁸³ But if the courts wish to apply it in an ideological neutral way, then a Section 202(c) case would be an excellent opportunity.

B. Practical Consequences

Beyond the doctrinal implications, there are practical consequences associated with the DOE's Section 202(c) orders for electric utilities and their customers, and more generally for electric grid governance. As described throughout this Essay, through both research and regulation, the federal government until now has consistently supported the development and deployment of new technologies, helping to build an electricity system that is more diverse than even the most optimistic World War II-era planners would likely have dreamed of. While no one would call it perfect, FERC has created a system of regulated markets overseen by a technically savvy and politically stable bureaucracy.¹⁸⁴ That system has helped produce a variety of good results,¹⁸⁵ and it did so with only light involvement from a series of presidents.

The Trump administration's interventions reflect a very different way of thinking about the role of government in managing the grid. In that alternative way of thinking, use of emergency authorities allows the administration to promote favored energy resources, like fossil fuels, regardless of costs and markets. Conventional and basic-level economic and political theories—including works that once were canonical on the political right—can easily predict the consequences: If business opportunities are allocated by centralized and political authorities who have a limited understanding of, or interest in, the economics of electricity, then consumer costs will rise and quality will drop.¹⁸⁸

Already, that is exactly what is happening. The Trump administration is embracing the technologies of the past, like decades-old coal plants with poor

¹⁸² See *supra* Part II (describing history and roles of federal agencies in grid governance).

¹⁸³ See, e.g., Jody Freeman & Matthew C. Stephenson, *The Anti-Democratic Major Questions Doctrine*, 2022 SUP. CT. REV. 1, 4 (2022) (describing the major questions doctrine as a “novel clear statement rule that not only ignores but inverts longstanding administrative law principles.”); Mila Sohoni, *The Major Questions Quartet*, 136 HARV. L. REV. 262, 266 (2022) (“[T]he new major questions doctrine allows the Court ample leeway to *preserve* major rules when the muse so moves it—even when those rules rest on statutory authority as contestable to the naked eye as the authority that underwrites rules that fail to pass muster.”).

¹⁸⁴ Michael Panfil & Rama Zakaria, *Uncovering Wholesale Electricity Market Principles*, 9 MICH. J. ENV'T & ADMIN. L. 145, 149 (2019) (“Although the Commission's makeup itself may change from year to year, the rationale and logic undergirding its work has been remarkably durable and consistent since the introduction of competitive wholesale markets.”).

¹⁸⁵ See *supra* notes 128-130 and accompanying text.

¹⁸⁸ See generally, e.g., FRIEDRICH A. HAYEK, *THE ROAD TO SERFDOM* (1944) (arguing that centralized planning leads to both despotism and poor economic outcomes); MILTON FRIEDMAN, *CAPITALISM AND FREEDOM* (1962) (advancing similar critiques of centralized economic power).

reliability records, high maintenance costs, and adverse environmental impacts.¹⁸⁹ Many of the plants in question are not even able to operate, undermining the DOE's claim that they are in any position to address "emergency" conditions under the statute.¹⁹⁰ The increased costs associated with the administration's Section 202(c) orders are staggering.¹⁹¹ One estimate puts the costs to consumers of keeping aging coal plants online at over \$3 billion a year.¹⁹²

There is another cost associated with the Section 202(c) orders beyond the immediate excess consumer costs. The DOE orders will inevitably discourage states and power companies from engaging in the type of rational long-term planning that FERC and state public utility commissioners have encouraged and, in some cases, required. Using the J.H. Campbell plant as an example, the electric utility, regional grid operator, and state and federal regulators identified an uneconomic resource that needed to be retired, planned years in advance to replace it with cheaper and cleaner resources, charged ratepayers for carrying out that plan, and then the DOE Secretary upended those plans just days ahead of the plant's retirement.¹⁹³ If such actions become expected, no electric utility or state regulator can be confident that resource plans and the commitments they have made to ratepayers will be carried out. The result is deeply destabilizing to the kind of sensible economic decision-making and resource planning that the private sector and state and federal regulators need to be able to engage in.

Moreover, the administration's use of Section 202(c) orders to commandeer long-term grid-planning is uniquely free from the substantive and procedural constraints that usually accompany federal administrative actions, both in the electricity sector and more generally. The orders are issued by the DOE Secretary without notice and comment,¹⁹⁴ the statute does not require consideration of costs

¹⁸⁹ See RICHARD L. REVESZ & JACK LIENKE, *STRUGGLING FOR AIR: POWER PLANTS AND THE "WAR ON COAL"* 10–12 (2016) (summarizing the environmental costs of coal); see also Tomich, *supra* 13 (discussing unreliability of plants subject to the 202(c) orders).

¹⁹⁰ See Tomich, *supra* note 13 (discussing operational failure of coal unit in Indiana and quoting utility's president as saying that required maintenance and upgrades "will require substantial investment to support an inefficient and increasingly unreliable asset."); Benjamin Storrow, *3 Coal Turbines Ordered to Stay Open by DOE Have Not Run*, CLIMATEWIRE (Apr. 10, 2026), <https://subscriber.politicopro.com/article/eenews/2026/04/10/3-coal-plants-ordered-to-stay-open-by-doe-have-not-run-00866256> (discussing reasons why multiple plants subject to 202(c) orders have not run or have run well below their historic averages either due to maintenance problems or because grid operators did not need them).

¹⁹¹ See Greg Alvarez, *DOE Forces Busted Coal Plant to Stay Online for "Energy Emergency" but Halts 2.5 Million Homes' Worth of New Power*, THE POWER LINE (Jan. 11, 2026), <https://thepowerline.substack.com/p/doe-forces-busted-coal-plant-to-stay>.

¹⁹² Michael Goggin, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants*, GRID STRATEGIES (Aug. 2025), https://earthjustice.org/wp-content/uploads/2025/08/grid-strategies_cost-of-federal-mandates-to-retain-fossil-burning-power-plants.pdf; see also Brown & Plumer, *supra* note 13 (identifying costs of at least \$3 billion per year).

¹⁹³ See *supra* notes 2-5, 157-163 and accompanying text (discussing circumstances of DOE's order).

¹⁹⁴ See 16 U.S.C. § 824a(c) (allowing orders "with or without notice, hearing, or report").

or other factors that usually are part of utility regulatory decisions;¹⁹⁵ and DOE has taken the position that as “emergency” decisions these actions should be given enormous deference.¹⁹⁶ As such, these actions are uniquely prone to arbitrary, impulsive, politically-driven decisionmaking—a mode of administrative action that is particularly unsuited to expertise-laden technical and policy questions like how best to meet resource adequacy needs over a long-term time horizon.¹⁹⁷ Consumers and the environment both will pay the price.

CONCLUSION

In years to come, grid managers will occasionally face genuine emergencies. Circumstances will arise, suddenly and without warning, that could not have been planned for, and those crises could require quick and short-term federal interventions in management of the grid. When those circumstances arise, the nation may appreciate the wisdom of including Section 202(c) in the Federal Power Act. But that sort of crisis intervention is not what has happened in 2025 and 2026. Instead, DOE has used Section 202(c) in ways that have no historical analog, neither during the crisis years of World War II nor in the decades since, and that are creating problems rather than resolving them. The immediate burdens on consumers will be substantial, and the long-term consequences for grid management may well be worse. Future administrations and present-day courts would do well to return Section 202(c) to its traditional place and, more broadly, to restore systems of grid governance that have served the nation relatively well.

¹⁹⁵ *See id.*

¹⁹⁶ *See* Respondents’ Initial Answering Brief, *Michigan v. U.S. Dep’t of Energy*, No. 25-1159 at 17-18, 47-48, 52, 61 (Consolidated with 25-1160 and 25-1162) (referring multiple times to the “broad discretion” Section 202(c) grants to DOE to determine what constitutes an emergency and the deference the court owes to DOE in exercising its judgment).

¹⁹⁷ *See, e.g.,* Ethan Howland, *Coal Plant Owners Say DOE “emergency” Order to Run it Violates Constitution*, UTIL. DIVE (Feb. 2, 2026) (quoting the CEO of Colorado utility that owns the coal plant as stating that the order violates the Federal Power Act and constitutes an unconstitutional taking of private property because it “requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources.”).

Appendix
Federal Power Act § 202(c) Orders (1941-2025)¹⁹⁸

Order	Date	Subject Matter	Direction	Duration
<u>Order No. 202-25-14</u>	December 2025 (renewed Mar. 2026)	446.4 MW coal plant in Colorado ordered to remain operational despite planned retirement date in Dec. 2025	DOE directed Tri-State Generation and Transmission Association and its co-owners to continue to operate the Craig Station in Colorado.	Continuous since December 30, 2025
<u>Order No. 202-25-13</u>	December 2025 (renewed Mar. 2026)	103.7 MW coal-fired generating unit in Indiana ordered to remain operational despite planned retirement in Dec. 2025	DOE directed CenterPoint Energy and the Midcontinent Independent System Operator, Inc. (MISO) to continue to operate the F.B. Culley Generating Station in Indiana.	Continuous since December 23, 2025
<u>Order No. 202-25-12</u>	December 2025 (renewed Mar. 2026)	Two 423.5 MW coal-fired generation units in Indiana ordered to remain operational despite planned retirement in Dec. 2025	DOE directed Northern Indiana Public Service Company and MISO to continue to operate the R.M. Schahfer Generating Station in Indiana.	Continuous since December 23, 2025
<u>Order No. 202-25-11</u>	December 2025 (renewed Mar. 2026)	729.9 coal-fired generation unit in Washington State ordered to remain operational despite planned retirement in Dec. 2025	DOE directed TransAlta to continue to operate the Centralia Generating Station in Washington.	Continuous since December 16, 2025
<u>Order No. 202-25-6</u>	July 2025 (extended Oct. 2025)	397 MW oil-burning generator unit in Maryland allowed to exceed its yearly operational hour allotment	In response to a request from regional transmission organization PJM, DOE permitted PJM and Talen Energy Corporation to dispatch an oil-burning generator unit beyond its yearly allotment of permitted operational hours when necessary to meet PJM's anticipated demand.	156 days
<u>Order No. 202-25-5</u>	June 2025	Additional generation permitted beyond authorized emissions limits	In response to a request from investor-owned utility Duke Energy Carolinas, DOE authorized utility to use its generating units as needed to meet demand regardless of emission or permit limitations due to expected weather-related energy shortfalls.	42 hours

¹⁹⁸ The information used to create this table is from the following sources: *DOE's Use of Federal Power Act Emergency Authority*, DEP'T OF ENERGY, <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority> (last visited Feb. 2, 2025); Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 839-46 (2025); ASHLEY J. LAWSON, CONG. RSCH. SERV., *THE FEDERAL POWER ACT: THE DEPARTMENT OF ENERGY'S EMERGENCY AUTHORITY* (Jan. 20, 2026), <https://www.congress.gov/crs-product/R48568>. The table includes DOE's renewal of orders issued in 2025 through April 1, 2026.

Order	Date	Subject Matter	Direction	Duration
<u>Order No. 202-25-4</u>	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Two 380 MW dual fuel oil-gas generating units in Pennsylvania, ordered to remain operational	DOE directed Constellation Energy and PJM Interconnection to continue to operate two natural gas and oil generating units set to retire on the Eddystone Generating Station in Pennsylvania despite their planned retirement in May 2025.	Continuous since May 30, 2025
<u>Order No. 202-25-3</u>	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	1560 MW coal plant in Michigan ordered to remain operational	DOE directed Midcontinent Independent System Operator, Inc. (MISO) and Consumers Energy to continue to operate the coal-fired Campbell Power Plant in Michigan despite its planned retirement in May 2025.	Continuous since May 23, 2025
<u>Order No. 202-25-2</u>	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Vegetation management ordered	DOE directed the Puerto Rico Electric Power Authority to conduct vegetation management to ensure the operate of the generation facilities as demanded by Order No. 202-25-1, below.	Continuous since May 16, 2025
<u>Order No. 202-25-1</u>	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Expanded generation ordered due to chronically weak power grid further damaged by natural disasters in Puerto Rico	DOE directed the Puerto Rico Electric Power Authority to dispatch generation units to expand baseload generation.	Continuous since May 16, 2025
<u>Order No. 202-24-1</u>	October 2024	Additional generation permitted beyond authorized emissions limits	In response to a request from Duke Energy Florida, DOE permitted Duke Energy Florida to dispatch additional generation despite emission and permit limits to meet load requirements due to expected shortfalls caused by Hurricane Milton.	3 days
<u>Order No. 202-23-1</u>	September 2023	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to dispatch additional generation despite emission and permit limits due to weather-related shortfalls caused by an extreme heat wave.	26.5 hours
<u>Order No. 202-22-4</u>	December 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from PJM Interconnection, DOE permitted PJM to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	30.5 hours
<u>Order No. 202-22-3</u>	December 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	36.5 hours

Order	Date	Subject Matter	Direction	Duration
<u>Order No. 202-22-2</u>	September 2022	Additional generation permitted beyond authorized emission limits	In response to a request from the Balancing Authority of Northern California (BANC), DOE permitted BANC to dispatch additional generation despite emission and permit limits due to expected shortfalls caused by extreme heat.	7 days
<u>Order No. 202-22-1</u>	September 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	7 days
<u>Order No. 202-21-2</u>	September 2021	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	60 days
<u>Order No. 202-21-1</u>	February 2021	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	5 days
<u>Order No. 202-20-2</u>	September 2020	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	8 days
<u>Order No. 202-20-1</u>	August 2020	Temporary interconnection permitted in response to weather-related shortages in Texas	In response to a request from CenterPoint Energy Houston Electric (CEHE), DOE permitted CEHE to utilize a temporary connection to another Texas utility system to restore electric service after Hurricane Laura caused grid outages.	46 days
<u>Order No. 202-17-2</u>	June 2017 (multiple renewals through Dec. 2018)	Use of noncompliant coal-fired generating units in Virginia permitted	In response to a request from PJM Interconnection, DOE permitted continued use of two coal-fired generation units that were noncompliant with the Mercury and Air Toxics Standards initially due to expected shortfalls caused by extreme heat. The order was renewed through December 2018 upon PJM's request to allow for continued use during the construction of a new transmission line that would augment the region's power grid.	630 days

Order	Date	Subject Matter	Direction	Duration
<u>Order No. 202-17-1</u>	April 2017	Use of noncompliant coal generating unit in Oklahoma permitted	In response to a request from Grand River Dam Authority (GRDA) in Oklahoma, DOE permitted GRDA to utilize a coal generating unit that was noncompliant with the Mercury and Air Toxics Standards to meet demand after two other units became inoperative after a local fire and flooding.	90 days
<u>Order No. 202-08-1</u>	September 2008	Temporary interconnection in Texas permitted	DOE authorized CenterPoint Energy to temporarily connect to other Texas utility systems to restore electric service after Hurricane Ike caused grid outages.	48 days
<u>Order No. 202-05-1</u>	September 2005	Temporary interconnection in Texas permitted	DOE authorized CenterPoint Energy to temporarily connect to other Texas utility lines to restore power lost as a result of Hurricane Rita.	34 days
<u>Order No. 202-05-3</u>	August 2005 (renewals through Jan. 2007)	Generating station in the DC area ordered to remain operational	In response to a request from the District of Columbia Public Service Commission, DOE required Mirant Corporation to continue operating its Potomac River generating station despite plans to cease operations. DOE found that ceasing operations of the station would likely cause outages.	558 days
<u>Order No. 202-03-1</u>	August 2003	Transmission ordered between New York and Connecticut	DOE ordered the New York Independent System Operator and ISO New England to require Cross-Sound Cable Company to operate between Connecticut and New York to ease shortages causing regional blackouts.	18 days
<u>Order No. 202-02-1</u>	August 2002	Transmission ordered between New York and Connecticut	DOE ordered the New York Independent System Operator and ISO New England to require Cross-Sound Cable Company to operate between Connecticut and New York to ease shortages causing regional blackouts.	47 days
<u>Order No. 202-00-1</u>	December 2000	Services ordered in California to fulfill unexpected shortfalls	DOE ordered certain entities to generate, deliver, and transmit energy when requested by the California Independent System Operator in response to unexpected shortfalls caused by the combined effect of inoperative facilities, water shortages, and market volatility.	7 days
<u>47 F.P.C. 747</u>	March 1972	Interconnection ordered in Ohio	Federal Power Commission ordered interconnection between Cleveland Electric Illuminating Co. and the City of Cleveland's Division of Water and Power due to potential shortages in isolated regions without external connections.	No termination specified
<u>38 F.P.C. 269</u>	August 1967	Interconnection ordered in Kentucky	Federal Power Commission ordered interconnection between Kentucky Utilities Co. and additional electrical systems due to potential shortages in isolated regions without external connections.	No termination specified

Order	Date	Subject Matter	Direction	Duration
<u>35 F.P.C. 629</u>	April 1966	Interconnection ordered in Georgia	Federal Power Commission ordered interconnection between Georgia Power Co. and Crisp County after several outages in the County revealed system inadequacies.	5 years and 9 months
<u>16 F.P.C. 823</u>	August 1956 (extended Sept. 1956)	Interconnection ordered between Wisconsin and Illinois to account for limited reserve generation capacity	Federal Power Commission ordered an increase in the interconnection capacity between Commonwealth Edison Co. and Wisconsin Electric Power Co. without affecting either company's jurisdictional status with the Commission.	4 months
<u>10 F.P.C. 1506 (1951)</u>	November 1951 (extended Aug. 1956)	Interconnection permitted between Wisconsin and Illinois	Federal Power Commission permitted interconnection between Wisconsin Electric Power Co. and Public Service Co. of Northern Illinois without subjecting either company to Commission jurisdiction with interconnection to be utilized during likely shortfalls given the high concentration of defense industries located in the region.	4 years and 9 months
<u>7 F.P.C. 574</u>	April 1948 (extended Feb. 1949, Dec. 1950)	Interconnection permitted in Texas	Federal Power Commission permitted interconnection in Texas without affecting companies' jurisdictional standing with the Commission in response to unexpected construction delays, equipment failures, load forecasts, and reduced hydroelectric output.	4 years and 8 months
<u>6 F.P.C. 320</u>	January 1947	Interconnection permitted in the Pacific Northwest	Federal Power Commission permitted interconnections to support the Pacific Northwest region in response to increased regional demand after returning to peacetime activity after WWII.	8 years
<u>3 F.P.C. 934</u>	February 1943	Increased generation and transmission permitted to support war efforts	Federal Power Commission permitted increased generation and transmission between Dairyland Power Cooperative and Northern States Power Co. to support regions experiencing increased demand caused by the production of farm products needed during wartime.	Wartime order
<u>3 F.P.C. 920</u>	February 1943	Transmission and delivery ordered in the Pacific Northwest to support war efforts	Federal Power Commission ordered the Washington Water Power Co. to deliver and transmit energy to Bonneville Power Administration to supply War Department facilities.	Wartime order
<u>3 F.P.C. 869</u>	November 1942	Interconnection ordered to support war efforts	Federal Power Commission ordered the interconnection of electric facilities in Connecticut in response to increased demand, limitations on supply and transportation, and restrictions on construction and maintenance because of the war effort.	Wartime order
<u>3 F.P.C. 715</u>	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the interconnection of Florida electric facilities to support increased demand associated with the war effort.	Wartime order

Order	Date	Subject Matter	Direction	Duration
3 F.P.C. 714	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the Florida Power & Light Co. and the City of Gainesville, Florida to construct transmission facilities and establish interconnections to support increased demand associated with the war effort.	Wartime order
3 F.P.C. 712	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the Florida Power & Light Co. and the City of Jacksonville, Florida to construct transmission facilities and establish interconnections in response to an increased demand related to war efforts.	Wartime order
2 F.P.C. 1095	December 1941	Interconnection and delivery ordered between Virginia and Maryland to meet increase in demand associated with war-related infrastructure	Federal Power Commission ordered interconnection between Virginia and Maryland to meet a sudden increase in demand resulting, in part, from the construction of a new War Department office building.	Wartime order
2 F.P.C. 1060	November 1941	Transmission and delivery ordered in the Southeast to support the war effort	Federal Power Commission ordered electric companies to transmit and deliver energy up to 10,000 kilowatts for use by the Pittsburgh Metallurgical Co., which was producing products of war.	Wartime order
2 F.P.C. 1055	October 1941	Delivery ordered in the Southeast to support the war effort	Federal Power Commission ordered delivery of electric energy to meet increased demand and correct generation shortages associated with wartime manufacturing, particularly aluminum production.	Wartime order
2 F.P.C. 461	Sept. 16, 1941 (extended Sept. 1942)	Additional water usage permitted on the Niagara River to increase electric generation in support of the war effort	Federal Power Commission permitted the Niagara Falls Power Co. to amend its license to increase the amount of water the company could divert from the Niagara River to increase generation in response to increased demand related to wartime production.	Wartime order
2 F.P.C. 1021	August 1941	Interconnection ordered in the Southeast to meet increased demand and insufficient generation	Federal Power Commission ordered additional interconnection to meet increased demand and insufficient generation.	Wartime order
2 F.P.C. 998	June 1941	Generation and delivery from Carolina Aluminum Company ordered to meet increased demand	Federal Power Commission ordered the Carolina Aluminum Co. to generate and deliver continuous electric supply from its hydroelectric plants to ensure maximum generation of aluminum products to support the war effort.	Wartime order
2 F.P.C. 997	June 1941	Curtailment of nonessential electric supply recommended	Federal Power Commission recommended that all public and private citizens in the southeastern region of the United States curtail the use of electric energy in light of increased demand associated with wartime production and reduced hydroelectric supply.	Wartime recommendation

Order	Date	Subject Matter	Direction	Duration
<u>2 F.P.C. 996</u>	June 1941	Interconnection ordered between Florida and Alabama	Federal Power Commission ordered interconnection between Florida and Alabama to meet increased demand and insufficient generation associated with wartime production.	Wartime order
<u>2 F.P.C. 995</u>	June 1941	Interconnection ordered between Florida and Georgia	Federal Power Commission ordered interconnection between Florida and Georgia to meet increased demand and insufficient generation associated with wartime production.	Wartime order
<u>2 F.P.C. 994</u>	June 1941	Interconnection ordered in Florida	Federal Power Commission ordered the interconnection of two Florida electric utilities to meet increased demand and insufficient generation associated with wartime production.	Wartime order
<u>2 F.P.C. 993</u>	June 1941	Interconnection ordered in Georgia	Federal Power Commission ordered the interconnection of two Georgia electric utilities to meet increased demand and insufficient generation associated with wartime production.	Wartime order
<u>2 F.P.C. 992</u>	June 1941	Interconnection ordered between Georgia and Louisiana	Federal Power Commission ordered the interconnection between Georgia and Louisiana to meet increased demand and insufficient generation associated with wartime production.	Wartime order
<u>2 F.P.C. 992</u>	June 1941	Interconnection ordered in North Carolina	Federal Power Commission ordered the interconnection of two North Carolina electric utilities to meet increased demand and insufficient generation in the southeastern region of the United States associated with wartime production.	Wartime order
<u>2 F.P.C. 991</u>	June 1941	Interconnection ordered in Florida	Federal Power Commission ordered the interconnection of two Florida electric utilities to meet increased demand associated with wartime production.	Wartime order
<u>2 F.P.C. 990</u>	June 1941	Emergency declared in the southeastern region of the United States due to insufficient generation	Federal Power Commission declared a state of emergency in the southeastern region of the United States given the increased demand for electric supply associated with wartime production and drought limiting hydroelectric generation. This declaration was the basis for all June 1941 FPC 202(c) orders listed above.	Wartime recommendation

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



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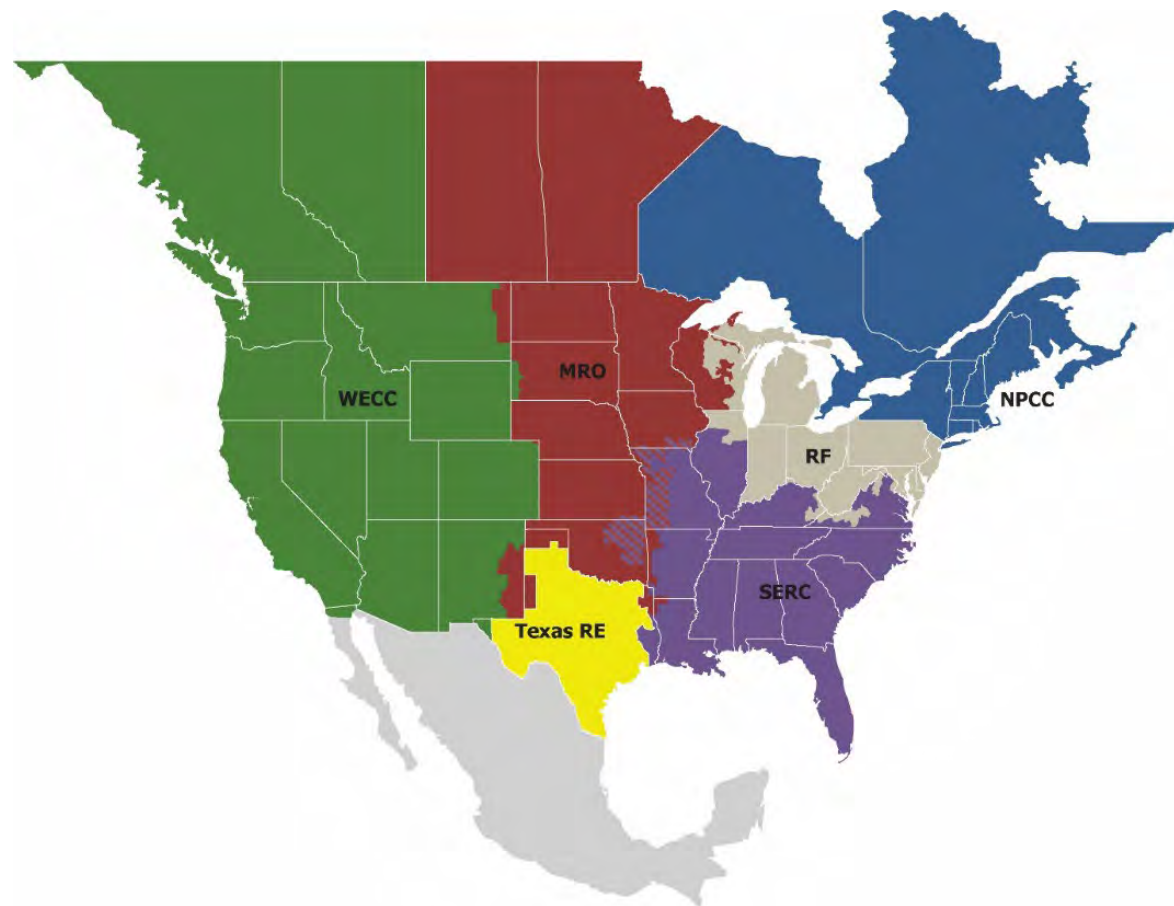
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

The *Long-Term Reliability Assessment* (LTRA), along with NERC's other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The [Summer Reliability Assessment](#) (SRA) and [Winter Reliability Assessment](#) (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts [special reliability assessments](#) on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- **State of Reliability Report (SOR):** The [SOR](#) contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO

Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.

- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the [ERO Event Analysis Program](#). This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC's [website](#).

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see [Preface](#)) on an assessment area basis (see [Regional Assessments Dashboards](#)) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The [Reliability Assessment Subcommittee](#) (RAS), at the direction of NERC's [Reliability and Security Technical Committee](#) (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO's Rules of Procedure¹ and Title 18, § 39.11² of the Code of Federal Regulations;³ this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.⁴

¹ NERC Rules of Procedure - Section 803

² Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

³ Title 18, § 39.11 of the Code of Federal Regulations

⁴ BPS reliability, as defined in the [How NERC Defines BPS Reliability](#) section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.⁵ Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC’s standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the [Demand Assumptions and Resource Categories](#) section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC’s reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:⁶

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity’s self-assessment.

⁵ [ERO Reliability Assessment Process Document](#)

⁶ Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year’s actual demand may deviate from the projection due to the inherent

- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading This Report

This report is compiled into two major parts:

- 1. A reliability assessment of the North American BPS with the following goals:**
 - a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
 - b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
 - c. Identify emerging reliability issues
 - d. Focus the industry, policymakers, and the general public’s attention on BPS reliability issues
 - e. Make recommendations based on an independent NERC reliability assessment process
- 2. A regional reliability assessment that contains the following:**
 - a. A 10-year data dashboard
 - b. Summary assessments for each assessment area
 - c. A focus on specific issues identified through industry data and emerging issues
 - d. A description of regional planning processes and methods used to ensure reliability

variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the *2025 LTRA*, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The [Capacity and Energy Risk Assessment](#) section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.⁷ Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

⁷ In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the [Capacity and Energy Risk Assessment](#).

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.⁸ **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in [Figure 1](#) and described in [Table 1](#).

⁸ The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See [Risk Categories](#) in this report for a complete description.

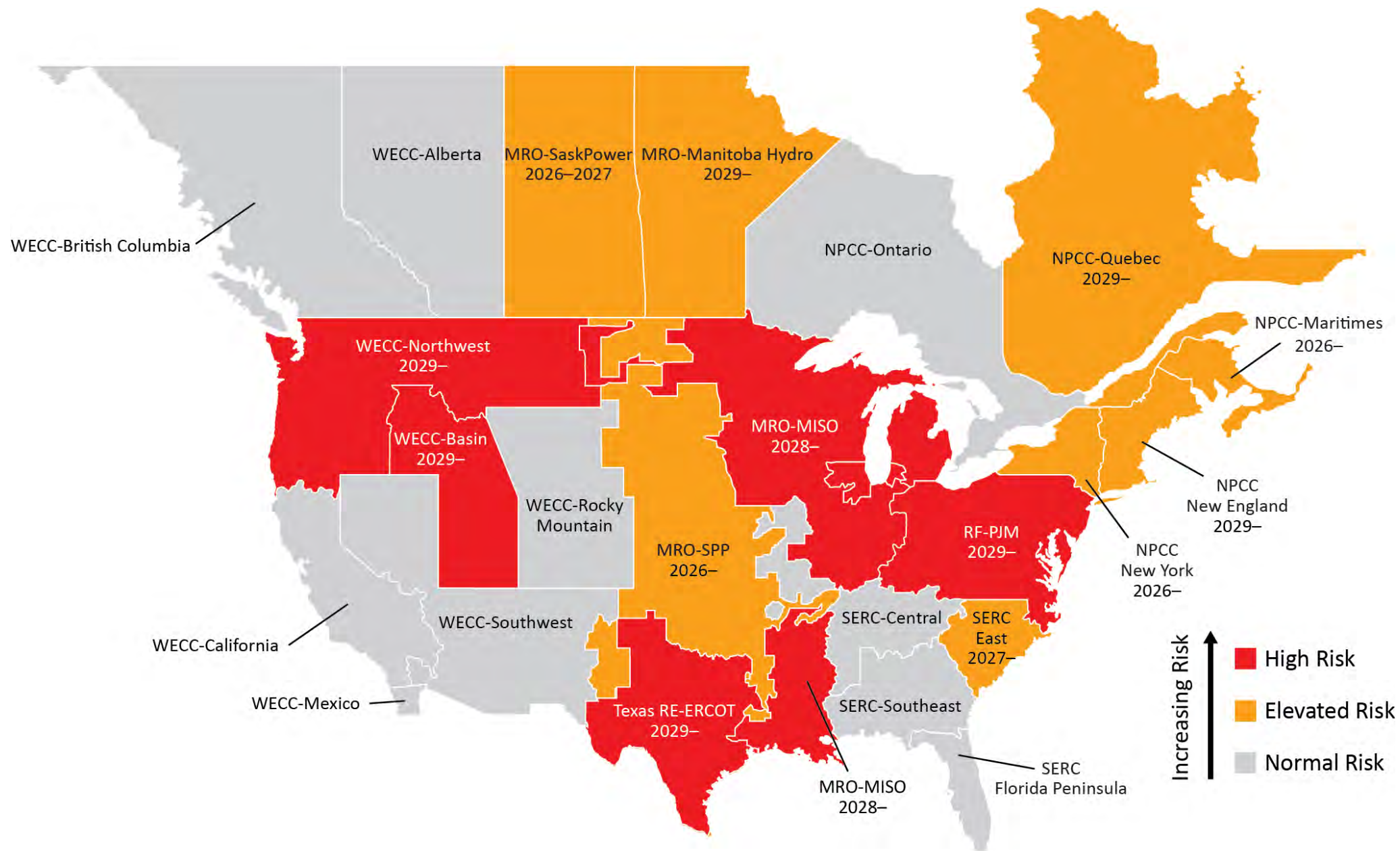


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

Table 1: Capacity and Energy Risk Assessment Area Summary

Assessment Area	Risk Level (High, Elevated, or Normal)					Risk Summary
	2026	2027	2028	2029	2030	
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved <i>Expedited Resource Addition Study</i> (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the 2025 LTRA. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
MRO-Manitoba						With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions.
MRO-SaskPower						With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy.
MRO-Southwest Power Pool (SPP)						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP's <i>Expedited Resource Adequacy Study</i> is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the 2024 LTRA, while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold.
NPCC-New England						Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions.
NPCC-New York						Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO 2025 Q3 <i>Star Report</i> .
NPCC-Québec						Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
Texas RE-ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since the 2024 LTRA, but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC-Basin						Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC-Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Regional Assessments Dashboards

The [Regional Assessments Dashboards](#) section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The [Capacity and Energy Risk Assessment](#) and [Regional Assessments Dashboards](#) sections provide details on these examples and initiatives in other assessment areas.

Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the [Demand Trends and Implications](#) and [Transmission Development and Interregional Transfer Capability](#) sections.

Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the 2024 LTRA by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year's LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

Transmission Development and Interregional Transfer Capability

Transmission projections reported for the 2025 LTRA reflect an increase in transmission development, continuing a trend that emerged in the 2024 LTRA. This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the 2024 LTRA 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-

Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,⁹ including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate *Interregional Transfer Capability Study (Canadian Analysis)*. About 4% of transmission projects reported for the 2025 LTRA are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the 2024 LTRA.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

⁹ [Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission](#)

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC’s Large Loads Action Plan¹⁰ and collaborate through NERC’s Large Loads Task Force.¹¹ ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year’s LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the 2026 LTRA and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC’s LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.
4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.
5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.¹² Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC’s LTRA and other assessment reports. All recommendations are listed in the [Recommendations and ERO Actions Summary](#).

¹⁰ NERC’s Large Loads Action Plan: <https://www.nerc.com/initiatives/large-loads-action-plan>

¹¹ NERC’s Large Loads Task Force webpage: [Large Loads Task Force \(LLTF\)](#)

¹² Essential Reliability Services:

<https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf>

Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such [considerations](#) have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC's LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

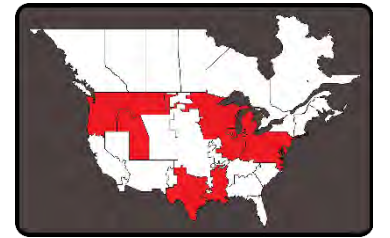
The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The [Demand Assumptions and Resource Categories](#) section provides further details on these approaches. Assessment area dashboards (see [Regional Assessments Dashboards](#)) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

For the 2025 LTRA, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.

An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See [Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area](#). Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.¹³ High risk areas are those where today's demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.



For the 2025 LTRA, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

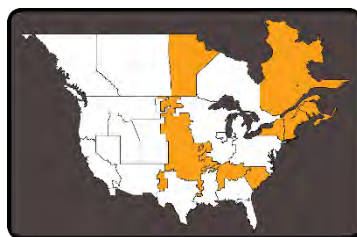
- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

¹³ See the NERC-National Academy of Engineering Workshop Report [Evolving Planning Criteria for a Sustainable Power Grid](#).

- Resource adequacy target(s) established by regulatory authority or system operator are not met.

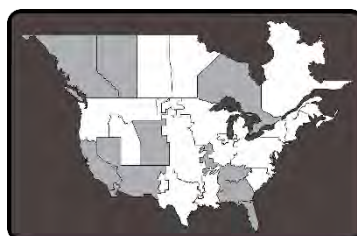
Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.

An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):



- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load

An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme¹⁴ conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*,



assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year's LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, [Evolving Planning Criteria for a Sustainable Power Grid](#), alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas' risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

¹⁴ Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

Table 2: Capacity and Energy Risk Assessment Numerical Summary

	NEUE (ppm)		LOLH (hours/year)		Anticipated Reserve Margin					Reference Margin Level ¹⁵				
	2027	2029	2027	2029	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
Summer-Peaking Areas														
MISO	1.13	42.39	0.23	6.61	11.0%	11.2%	9.5%	8.6%	4.3%	8.1%	8.3%	8.5%	8.5%	8.5%
MRO-SPP	0.00	0.00	0.00	0.00	32.4%	30.3%	28.4%	25.1%	22.6%	19.0%	19.0%	19.0%	19.0%	19.0%
NPCC-New England	0.00	0.02	0.00	0.00	18.3%	21.7%	24.8%	23.7%	23.6%	13.4%	13.0%	13.0%	13.0%	13.0%
NPCC-New York	0.00	0.08	0.00	0.03	22.3%	24.5%	24.5%	23.6%	22.5%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	0.00	0.00	0.00	0.00	29.6%	19.8%	28.1%	18.7%	19.7%	16.1%	19.0%	22.6%	15.8%	19.5%
PJM	3.50	65.50	0.61	9.97	29.7%	28.3%	24.3%	18.9%	13.9%	18.6%	20.1%	21.9%	23.9%	26.3%
SERC-Central	0.00	0.00	0.00	0.00	19.1%	20.8%	19.7%	18.5%	16.5%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	0.98	2.27	0.15	0.33	30.6%	30.5%	30.5%	31.5%	34.9%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	0.00	0.00	0.00	0.00	27.4%	25.2%	24.3%	22.6%	21.1%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	0.00	0.00	0.00	0.00	35.9%	29.5%	29.8%	24.9%	20.9%	15.0%	15.0%	15.0%	15.0%	15.0%
Texas RE-ERCOT	8.70	18.84	0.95	3.64	28.2%	30.5%	31.8%	30.8%	29.9%	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-Basin	0.04	2,250	3.00	310.00	36.3%	37.9%	27.4%	19.7%	15.2%	13.5%	14.0%	13.6%	12.4%	12.3%
WECC-California	0.00	0.00	0.00	0.00	53.2%	47.0%	46.1%	45.6%	42.7%	20.3%	19.2%	19.3%	19.7%	19.3%
WECC-Mexico	0.00	0.00	0.00	0.00	14.9%	13.8%	29.9%	27.0%	24.6%	7.8%	8.0%	9.1%	7.2%	7.0%
WECC-Rocky Mountain	0.00	0.00	0.00	0.00	51.3%	60.0%	53.2%	38.1%	30.5%	17.8%	17.0%	16.2%	16.1%	15.7%
WECC-Southwest	0.00	0.00	0.00	0.00	41.1%	39.6%	38.6%	38.4%	36.1%	13.3%	13.7%	13.6%	12.6%	12.2%
Winter-Peaking Areas														
MRO-Manitoba Hydro	0.12	0.23	0.03	0.06	13.9%	16.7%	15.4%	13.6%	1.2%	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	5.24	0.19	1.09	0.05	25.9%	35.0%	33.4%	32.3%	31.2%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Maritimes	0.52	0.25	0.25	0.10	17.2%	18.5%	25.6%	23.0%	21.7%	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-Québec	0.00	0.29	0.00	0.11	15.6%	16.7%	14.7%	13.0%	11.5%	11.9%	12.2%	12.2%	12.2%	12.2%
WECC-Alberta	0.00	0.00	0.00	0.00	36.2%	45.3%	40.7%	38.0%	33.0%	11.8%	17.6%	14.3%	15.6%	11.6%
WECC-British Columbia	0.00	0.00	0.00	0.00	23.4%	19.1%	19.5%	24.1%	24.2%	11.7%	12.1%	12.1%	11.6%	11.6%
WECC-Northwest	0.00	36.64	0.00	85.00	30.2%	29.3%	23.3%	19.1%	15.7%	17.8%	17.4%	16.1%	15.8%	15.5%

¹⁵ Refer to the [Regional Assessments Dashboards](#) and the [Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area](#) table.

High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the [Regional Assessments Dashboards](#) section.

MISO (Normal Risk 2026/ Elevated Risk 2027/ High Risk 2028–)

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year’s projection in the 2024 LTRA) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO’s accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the [ERAS](#) process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the 2025 LTRA. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see [Table 3](#)). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

	2027	2029
EUE (MWh)	797	31,654
NEUE (ppm)	1.13	42.39
LOLH (hours per Year)	0.23	6.61
Category	Elevated	High

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see [Figure 2](#)). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

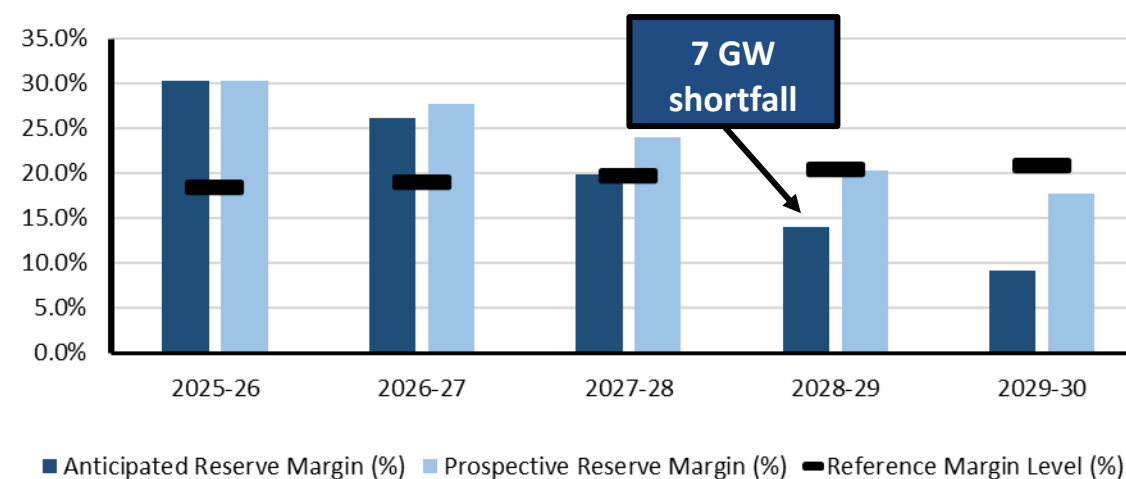
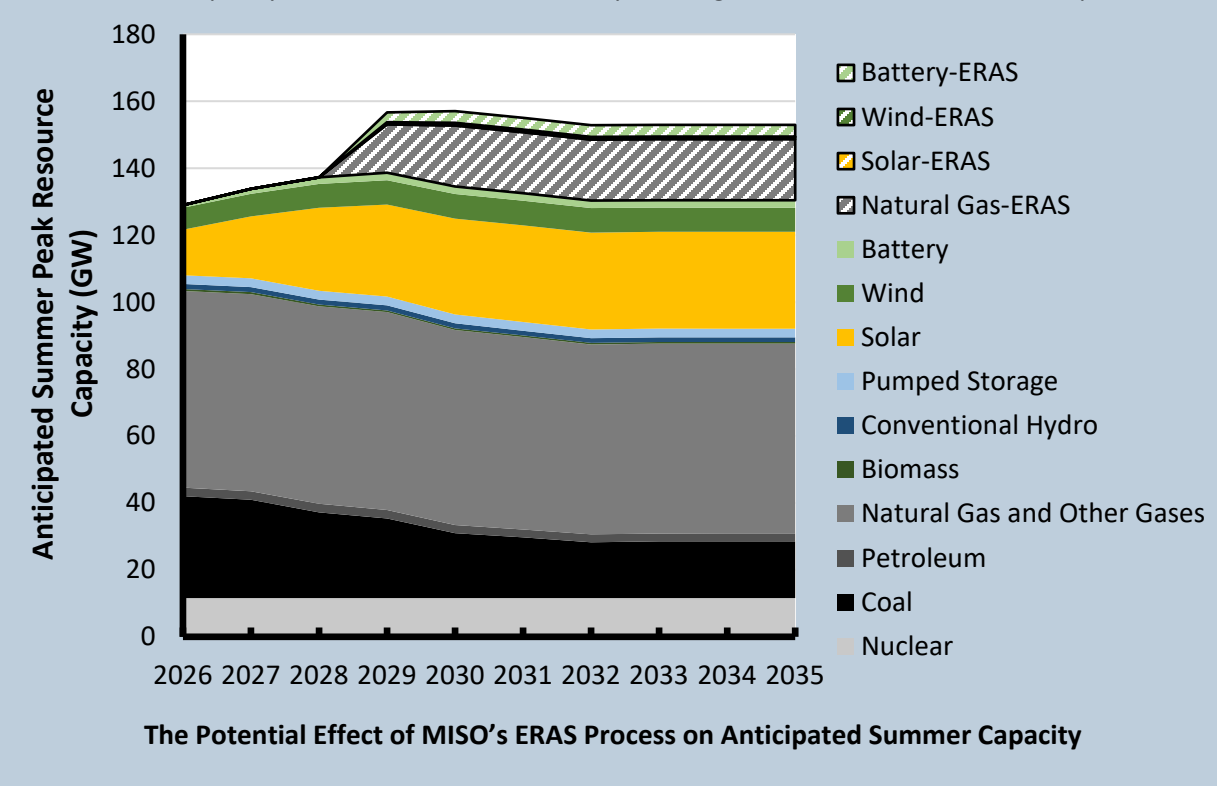


Figure 2: MISO Winter Planning Reserve Margins

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

The timing of FERC’s approval of MISO’s ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year’s ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the 2026 LTRA, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



PJM (Elevated Risk 2026–2028/ High Risk 2029–)

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM’s annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year’s projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM’s new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM’s limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM’s internal generation capacity), have led to a projection that PJM’s ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see Figure 3).

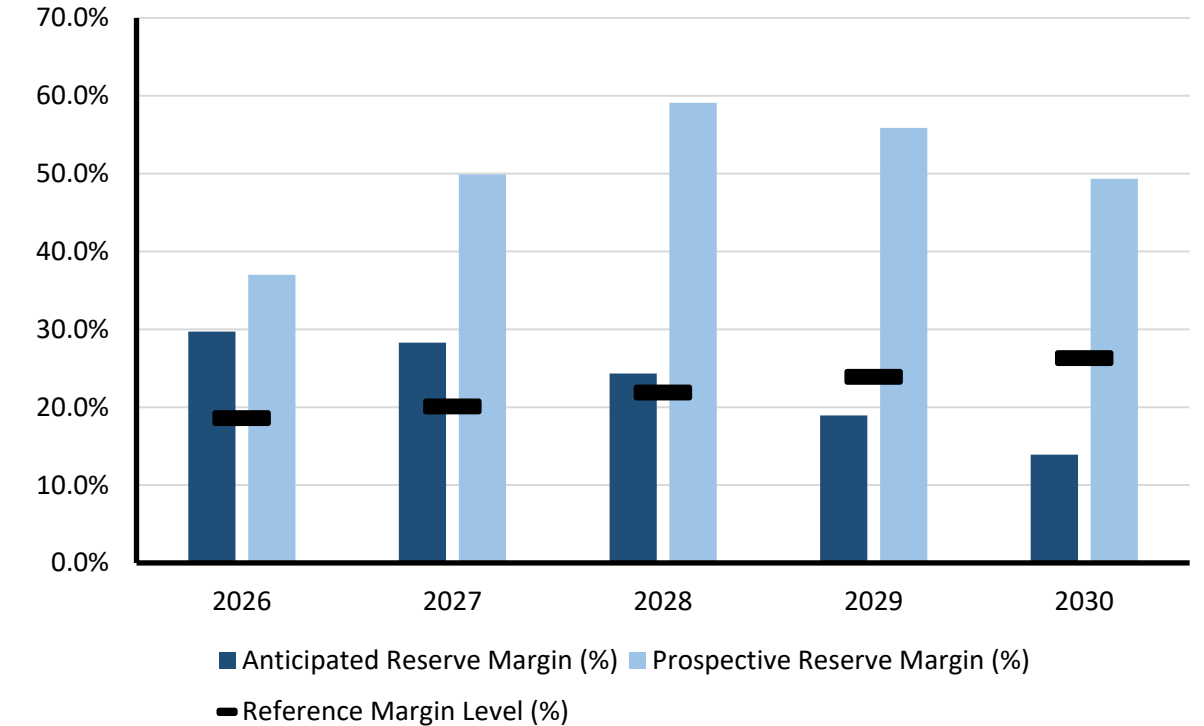


Figure 3: PJM Summer Planning Reserve Margins

As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM's new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original 2025 LTRA data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original 2025 LTRA data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM's current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see [Table 4](#)). Because this year's ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year's LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

Table 4: PJM Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	538	3,251	67,581
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.1	0.61	9.97
Category	Elevated	Elevated	High
*Provides the 2024 ProbA Results for Comparison			

Texas RE-ERCOT (Elevated Risk 2026–2028/ High Risk 2029–)

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the 2025 LTRA, ERCOT's DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the 2024 LTRA), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see [Figure 4](#)).

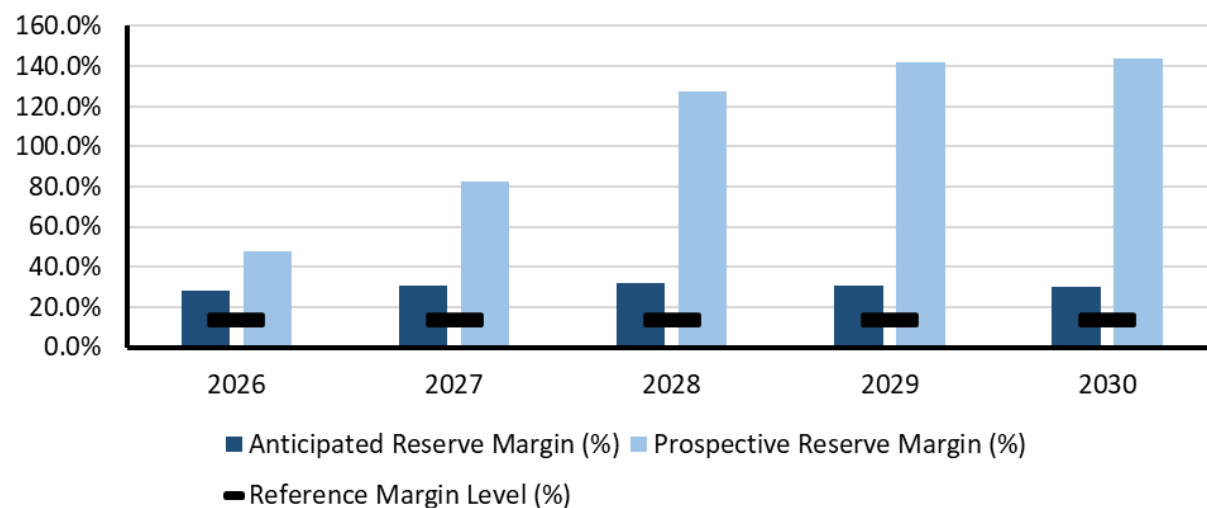


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

ERCOT's Planning Reserve Margins in the 2025 LTRA are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the 2024 LTRA, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see Table 5). ERCOT's ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT's market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

Table 5: Texas RE-ERCOT Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11,090	5,865	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.95	3.64
Category	Elevated	Elevated	High

*Provides the 2024 ProbA Results for Comparison

ERCOT's ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

WECC-Basin (Elevated Risk 2026–2028/High Risk 2029–)

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.¹⁶ The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see [Table 6](#)).

Table 6: WECC Basin Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2,250.70
LOLH (hours per Year)	N/A	3.00	310.00
Category	-	High	High
*No prior results as the assessment area is new for the 2025 LTRA.			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC’s probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

WECC-Northwest (Normal Risk 2026–2028/ High Risk 2029–)

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from

¹⁶ Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see [Table 7](#)).

Table 7: WECC Northwest Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0.00	36.64
LOLH (hours per Year)	N/A	0.00	85.00
Category	N/A	Normal	High
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

Elevated-Risk Area Details

The below areas are classified as **Elevated Risk** as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the [Regional Assessments Dashboards](#) section.

MRO-Manitoba Hydro (Normal 2026–2028/ Elevated 2029–)

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the 2024 LTRA. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the 2024 LTRA. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro’s 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see [Table 8](#)). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

	2026*	2027	2029
EUE (MWh)	5	3	6
NEUE (ppm)	0.18	0.12	0.23
LOLH (hours per Year)	0.06	0.03	0.06
Category	Normal	Normal	Elevated

* Provides the 2024 ProbA Results for Comparison

MRO-SaskPower (Elevated 2026–2027/ Normal 2028–)

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the 2024 LTRA’s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year’s projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower’s RML for the entire 10-year period of the 2025 LTRA.

SaskPower is a winter-peaking system, but MRO-Saskatchewan’s probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower’s projected resource additions (see [Table 9](#)).

	2026*	2027	2029
EUE (MWh)	76	145	5
NEUE (ppm)	2.81	5.24	0.19
LOLH (hours per Year)	0.55	1.09	0.05
	Elevated	Elevated	Normal

*Provides the 2024 ProbA Results for Comparison

MRO-SPP (Elevated 2026–)

Resource additions and delays in generator retirements since the 2024 LTRA are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP’s ARMs are projected to remain above RMLs until after 2030 (see [Figure 5](#)). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.¹⁷ SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

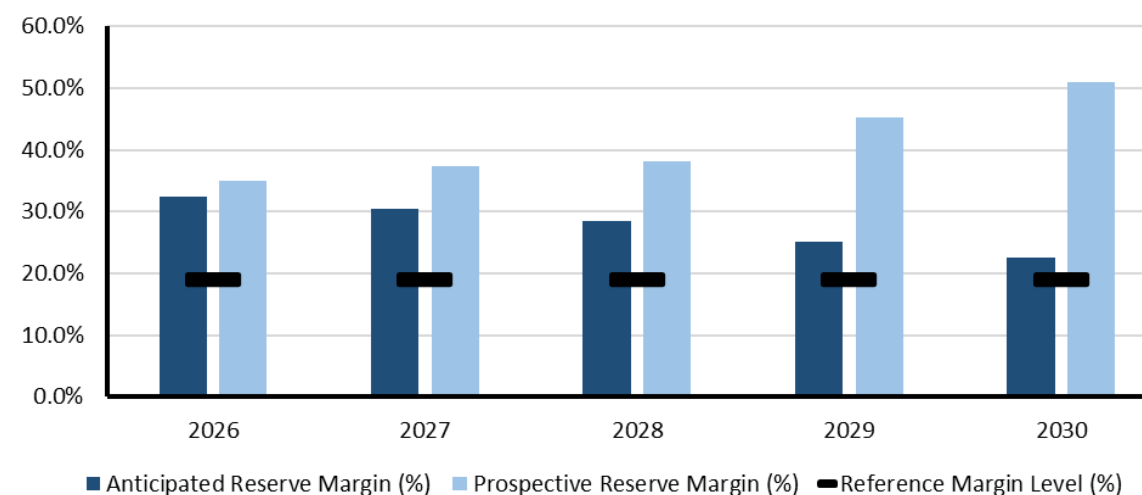


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

¹⁷ See [NERC 2025 Summer Reliability Assessment](#)

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

NPCC-Maritimes (Elevated 2026–)

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see [Table 10](#)). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

Table 10: NPCC-Maritimes Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	5	15	7
EUE (ppm)	0.17	0.52	0.25
LOLH (hours per Year)	0.09	0.25	0.10
*Results from the 2024 The ProbA simulations			

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

NPCC-New England (Normal 2026 –2028/ Elevated 2029–)

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see [Table 11](#)). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

Table 11: NPCC New England Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11	<1	2
NEUE (ppm)	0.10	0.00	0.02
LOLH (hours per Year)	0.10	0.00	0.00
Category	Normal	Normal	Normal
* Provides the 2024 ProbA results for Comparison			

NPCC-New York (Elevated 2026–)

The LTRA anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in [Table 12](#).

Table 12: NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	<1	12
NEUE (ppm)	0.01	0.00	0.08
LOLH (hours per Year)	0.01	0.00	0.03
Category	Normal	Normal	Normal
* Provides the 2024 ProbA results for Comparison			

While NPCC's ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the *2025 Quarter 3 Short-Term Assessment of Reliability (STAR)*,¹⁸ identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

NPCC-Québec (Normal 2026–2028| Elevated 2029–)

Québec's demand forecast has increased since the *2024 LTRA*, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec's demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the *2024 LTRA*.

With stable resources over the 10-year assessment period, Québec's ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See [Table 13](#).

Table 13: NPCC Québec Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	8	8	63
NEUE (ppm)	0.04	0.00	0.29
LOLH (hours per Year)	0.01	0.00	0.11
Category	Normal	Normal	Elevated
* Provides the 2024 ProbA results for Comparison			

SERC-East (Normal 2026| Elevated 2027–)

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in [Table 14](#) below.

Table 14: SERC-East ProbA Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	232	539
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.15	0.33
Category	Normal	Elevated	Elevated
* Provides the 2024 ProbA Results for Comparison			

¹⁸ Additional details available in the report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/>

Normal-Risk Area Details

All other assessment areas (see [Figure 1](#)) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The [Capacity and Energy Risk Assessment](#) section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the 2025 LTRA assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding [Capacity and Energy Risk Assessment](#), NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC’s risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the 2024 LTRA (see [Figure 6](#)). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year’s LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

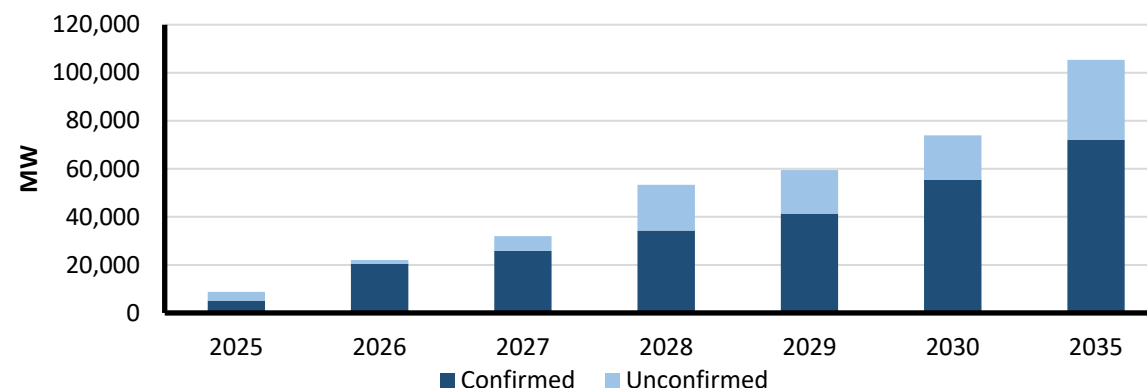


Figure 6: Projected Generation Retirement Capacity Through 2035

[Figure 7](#) shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.¹⁹ MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the [Risk from Additional Generator Retirements](#) section.

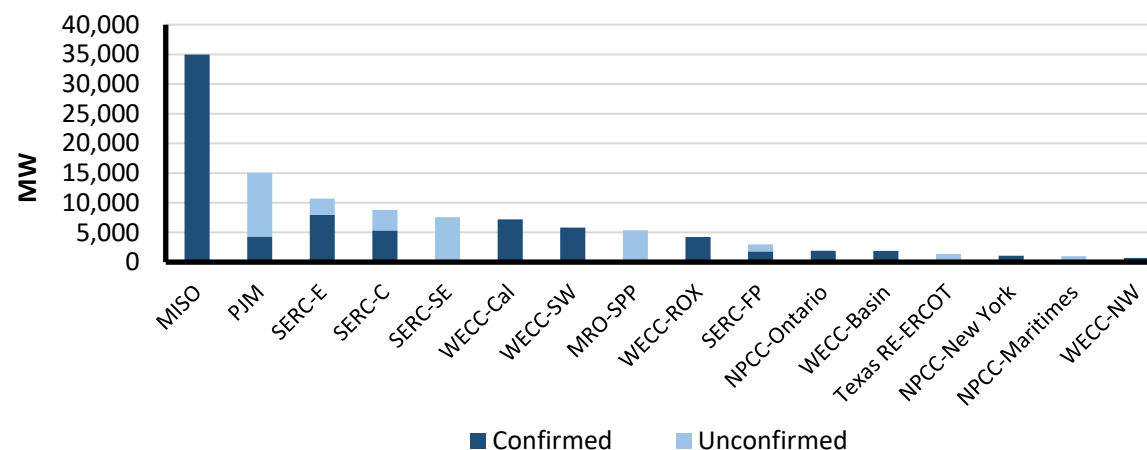


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

¹⁹ Confirmed generator retirements are reported to NERC by each assessment area in this 2025 LTRA development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each

assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the [Executive Summary](#).

Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. [Table 15](#) includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

Attributes	Objective	Implementation
1. Uses Energy Risk Criteria	To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics.	Establish criteria based on EUE or similar energy risk metric(s).
2. Evaluates Resource Contributions at Risk Periods	As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve.	Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods.
3. Load Forecasting Accounts for Growth Uncertainty	Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty.	Capture the forecast drivers needed for the area and address uncertainties.
4. Considers Effect of Extreme Scenarios on Adequacy	To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS.	Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration.
5. Includes Coordinated Interregional Transfer Capability	Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors.	Model transfer limits and deliverability; implement processes for seams coordination.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See [Figure 8](#) for seasonal peak demand growth over the current and prior assessment periods and [Figure 9](#) for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year's 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC's tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in [Figure 10](#).

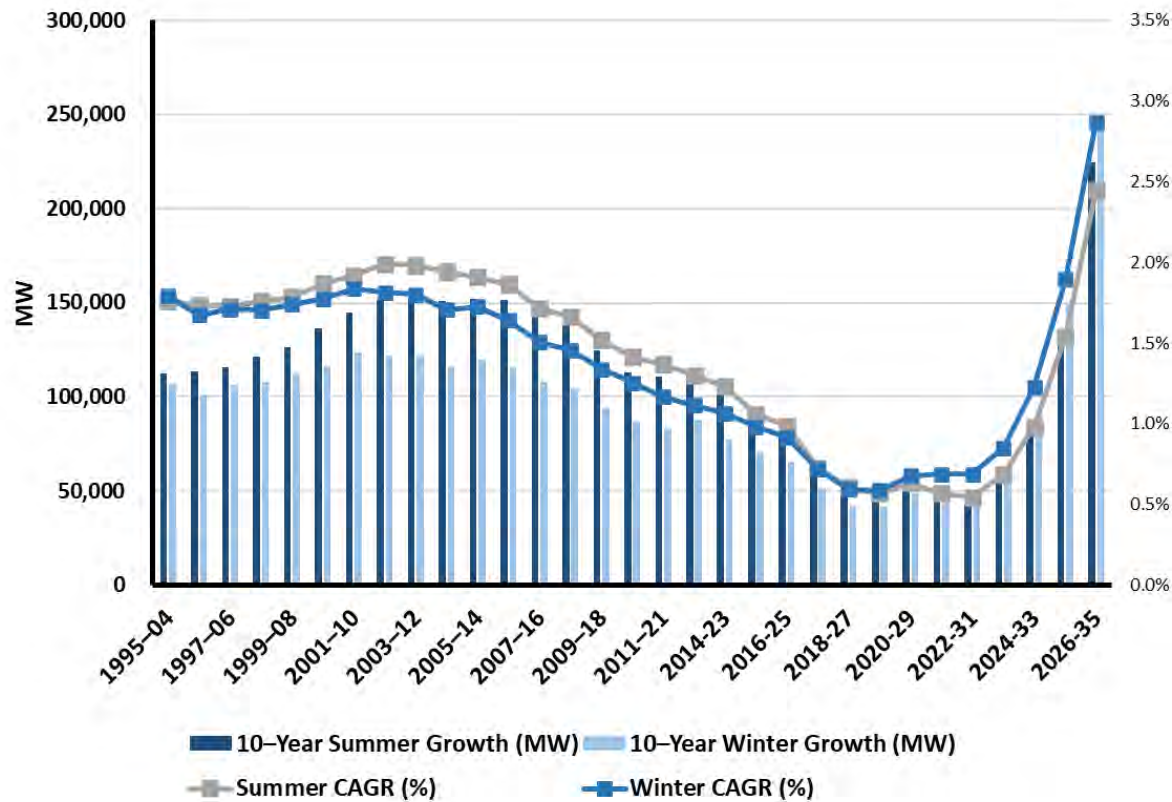


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

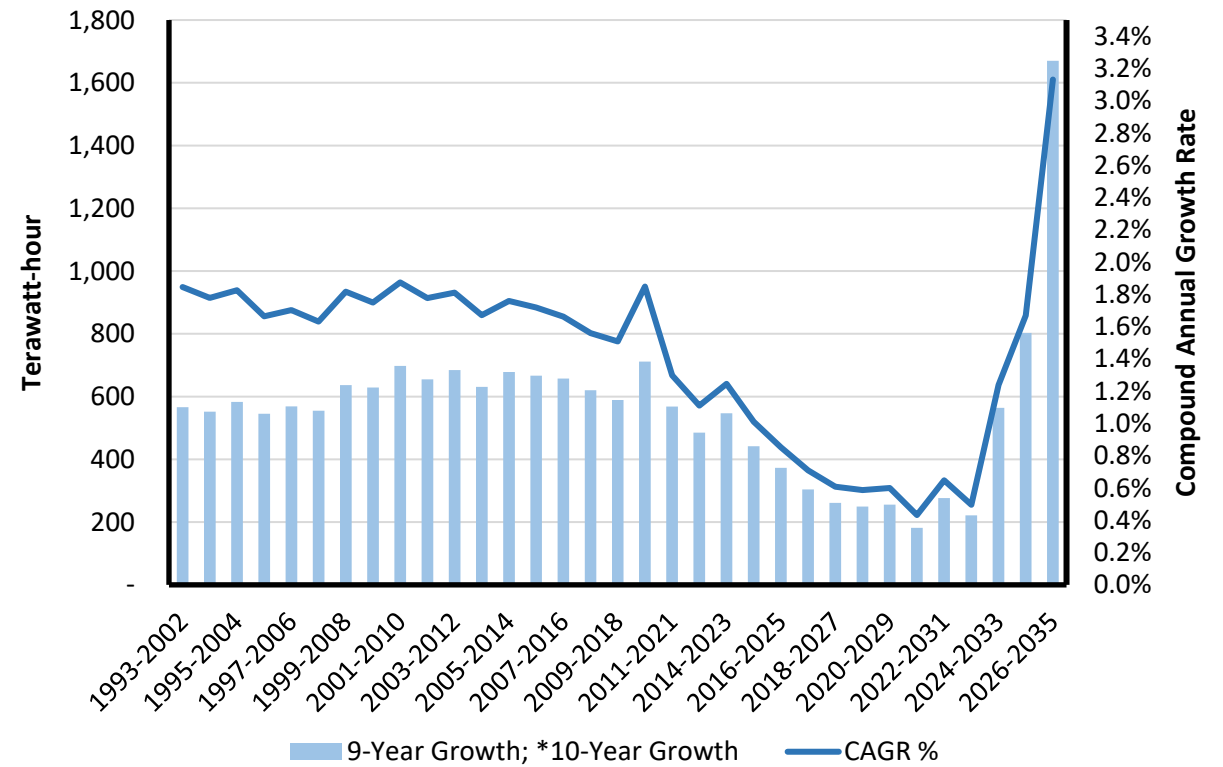


Figure 9: Net Energy for Load Growth and Rate Projections

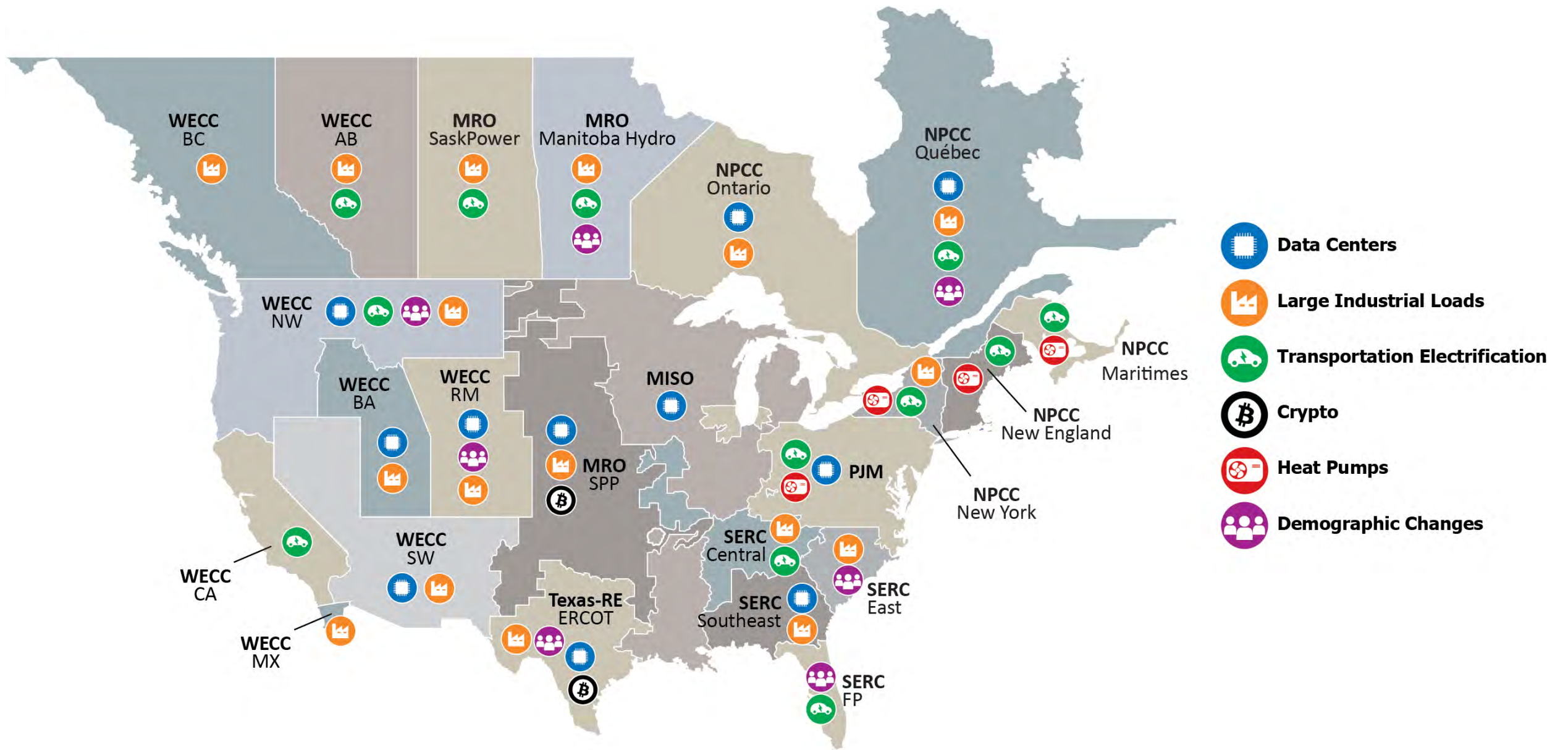


Figure 10: Primary Demand Drivers by Assessment Area

Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the 2025 LTRA reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See Figure 11 and Figure 12 for projections in ERCOT and most WECC assessment areas, respectively.

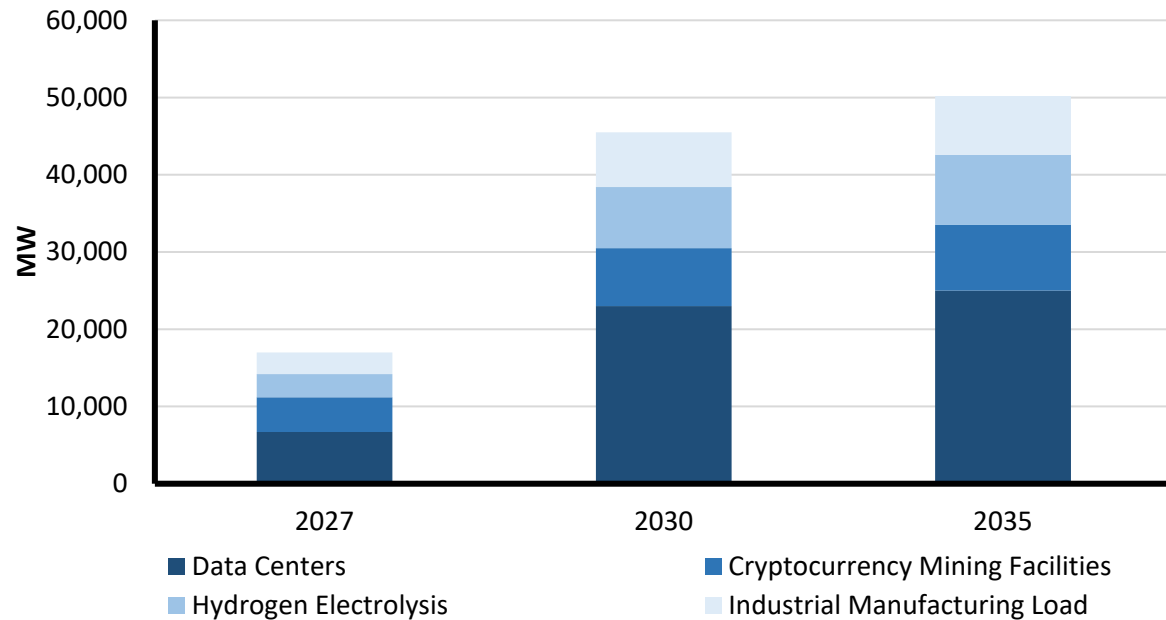


Figure 11: Large-Load Projection Breakdown in ERCOT

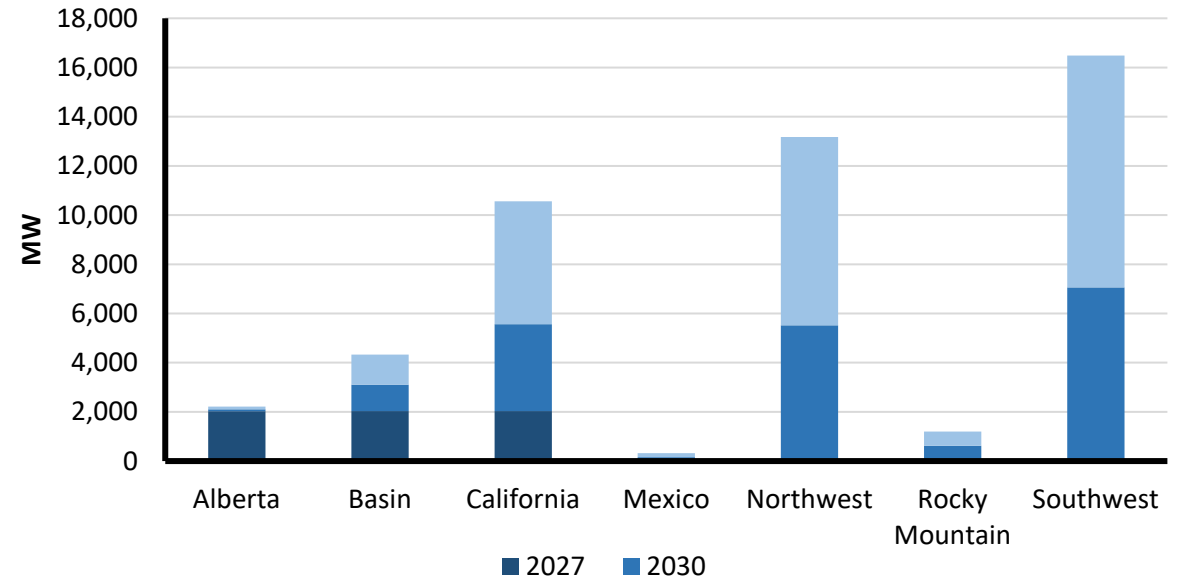


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.²⁰

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events²¹ with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC's RSTC established a Large Loads Task Force (LLTF)²² to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*²³ in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.²⁴

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the 2024 LTRA, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro's winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower's winter CAGR fell from 1.32% to 0.89%, NPCC-New England's summer CAGR from 1.28% to 1.05%, NPCC-New York's summer CAGR from 0.87% to 0.84%, and SERC-East's summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are

planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

Demand Response

Demand-side management programs are growing for many assessment areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. [Figure 13](#), [Figure 14](#), and [Figure 15](#) show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

²⁰ Planned revisions to PJM's treatment of large load forecasts from PJM's Load Analysis Subcommittee: [20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf](#)

²¹ "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

²² NERC Large Loads Task Force webpage: [Large Loads Task Force \(LLTF\)](#)

²³ The LLTF's [Characteristics and Risks of Emerging Large Loads](#) White Paper

²⁴ The LLTF's [action plan](#) is updated regularly and contains links to white papers, guidance, and presentations.

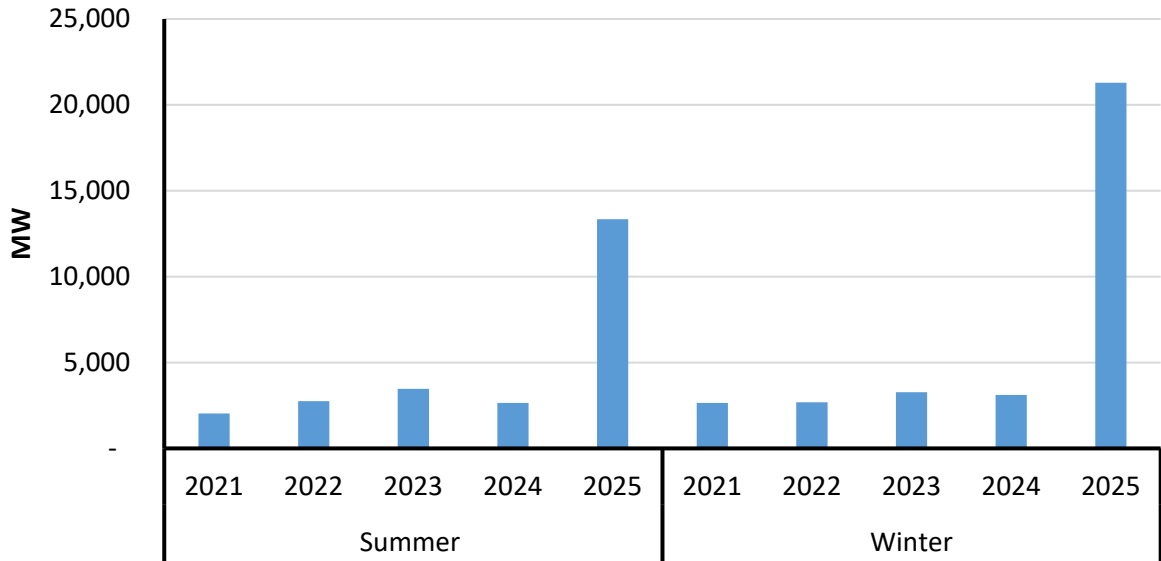


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

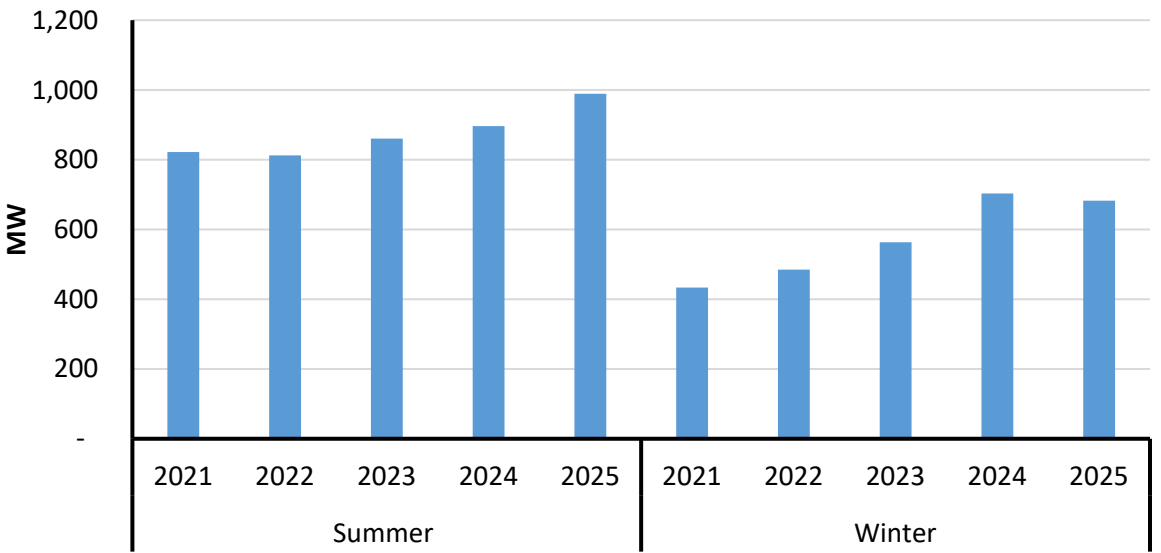


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

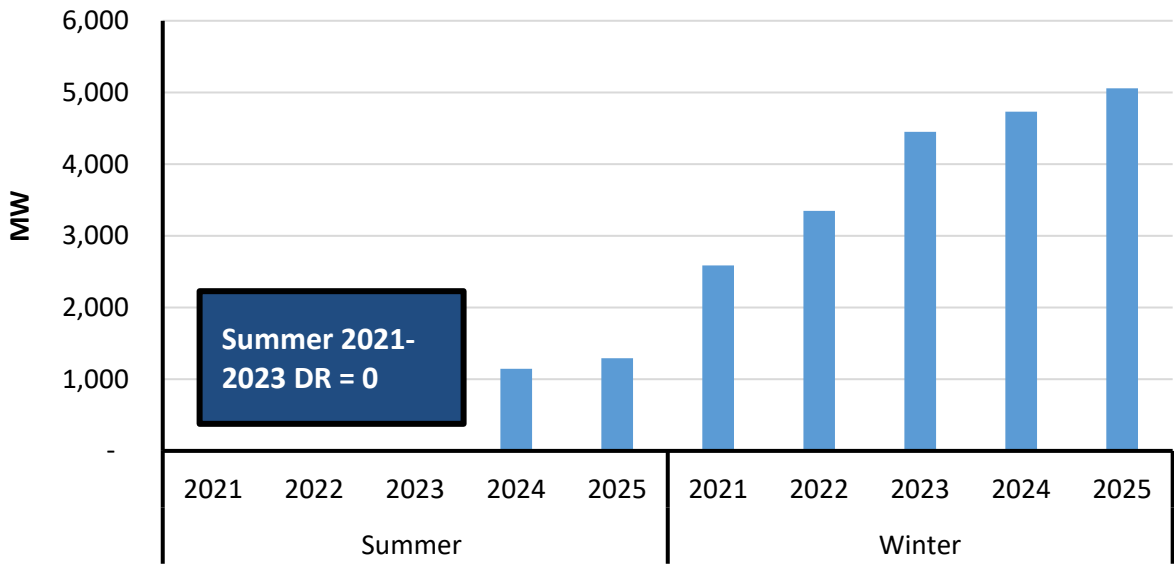


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year noticeably affected resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see [Table 16](#)).

Resource Type	2024 Capacity (MW)	2025 Capacity (MW)	Difference (MW)
Coal	180,402	166,799	- 13,603
Petroleum	30,987	27,931	- 3,056
Natural Gas	484,148	479,901	- 4,247
Biomass	7,381	7,181	- 200
Solar	66,293	70,723	+ 4,430
Wind	31,370	35,121	+ 3,751
Geothermal	3,881	2,932	- 949
Conventional Hydro	105,792	111,117	+ 5,325
Run-of-River Hydro	2,047	2,017	- 30
Pumped Storage	19,422	19,734	+ 312
Nuclear	105,384	105,389	+ 5
Hybrid	1,322	1,102	- 220
Other	774	830	+ 56
Battery	8,587	23,267	+ 14,680
Total	1,047,790	1,068,514	+ 6,254

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

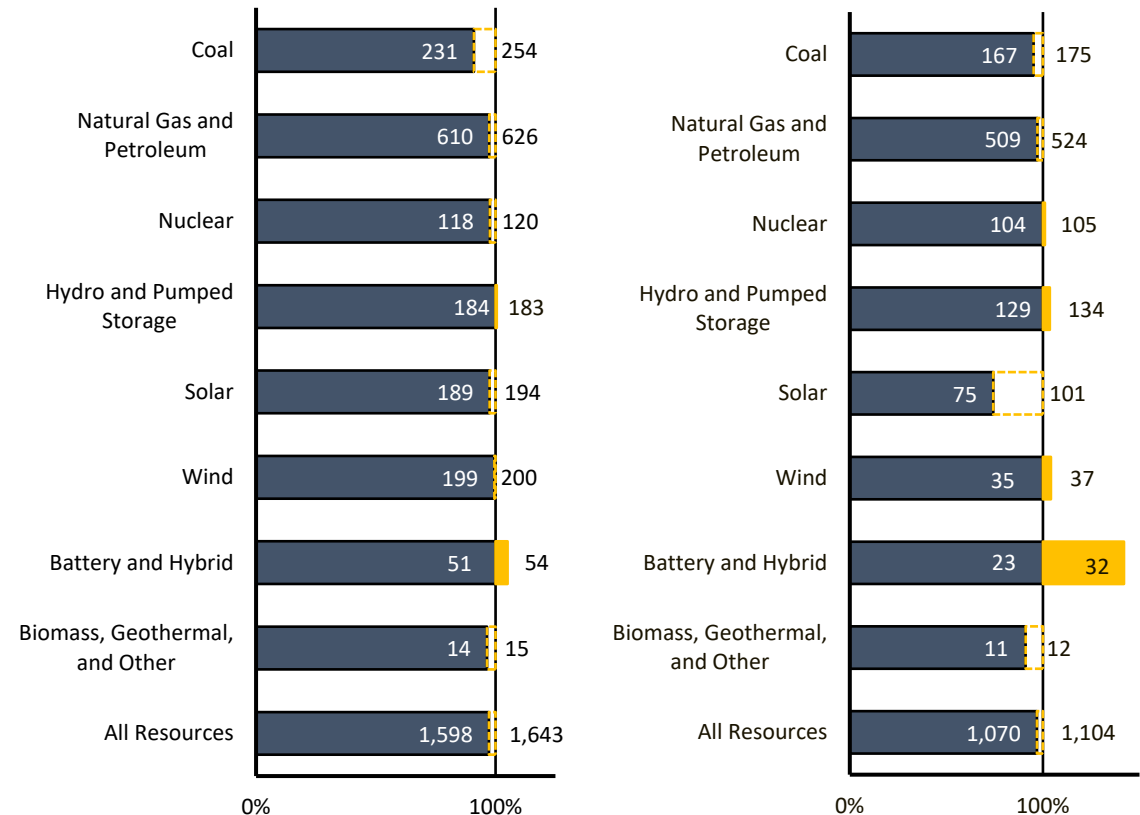


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to 2024 LTRA Projections

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in **Figure 16** above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

Planned On-Peak Capacity Additions

New resources are added to the BPS through each area’s interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. **Figure 16** above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

Figure 17 illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see **Demand Assumptions and Resource Categories**). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see **Figure 18**). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in **Figure 17**, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2’s 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain

capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM’s [Reliability Resource Initiative](#), MISO’s [ERAS](#) process, and SPP’s [Expedited Resource Adequacy Study](#).

In a shift from a key insight from the 2024 LTRA, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year’s 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

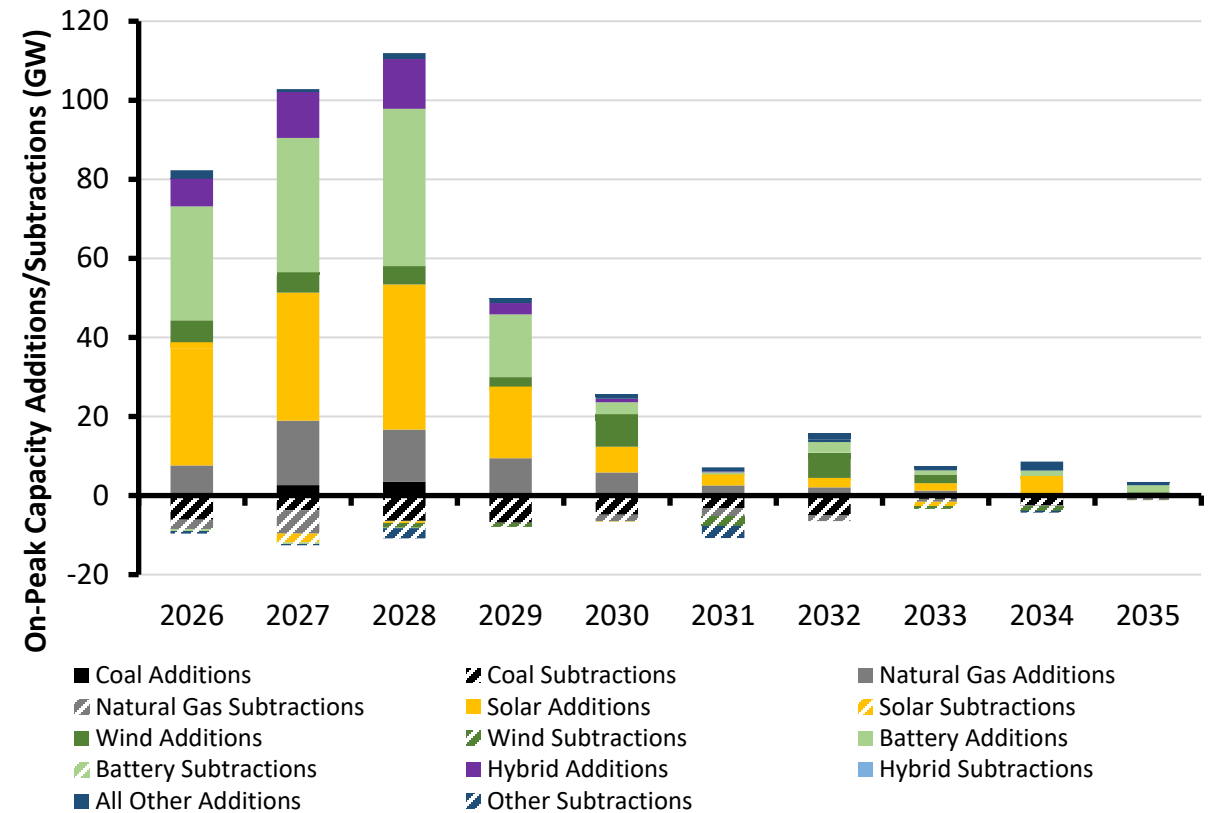


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

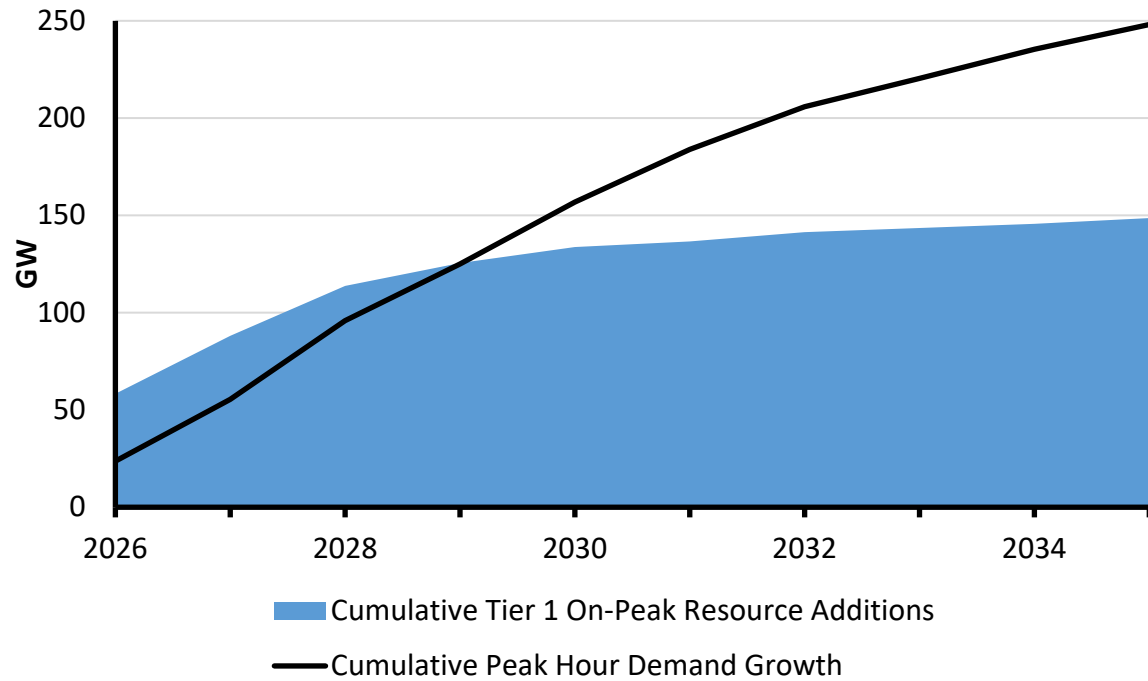


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. Figure 19 shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

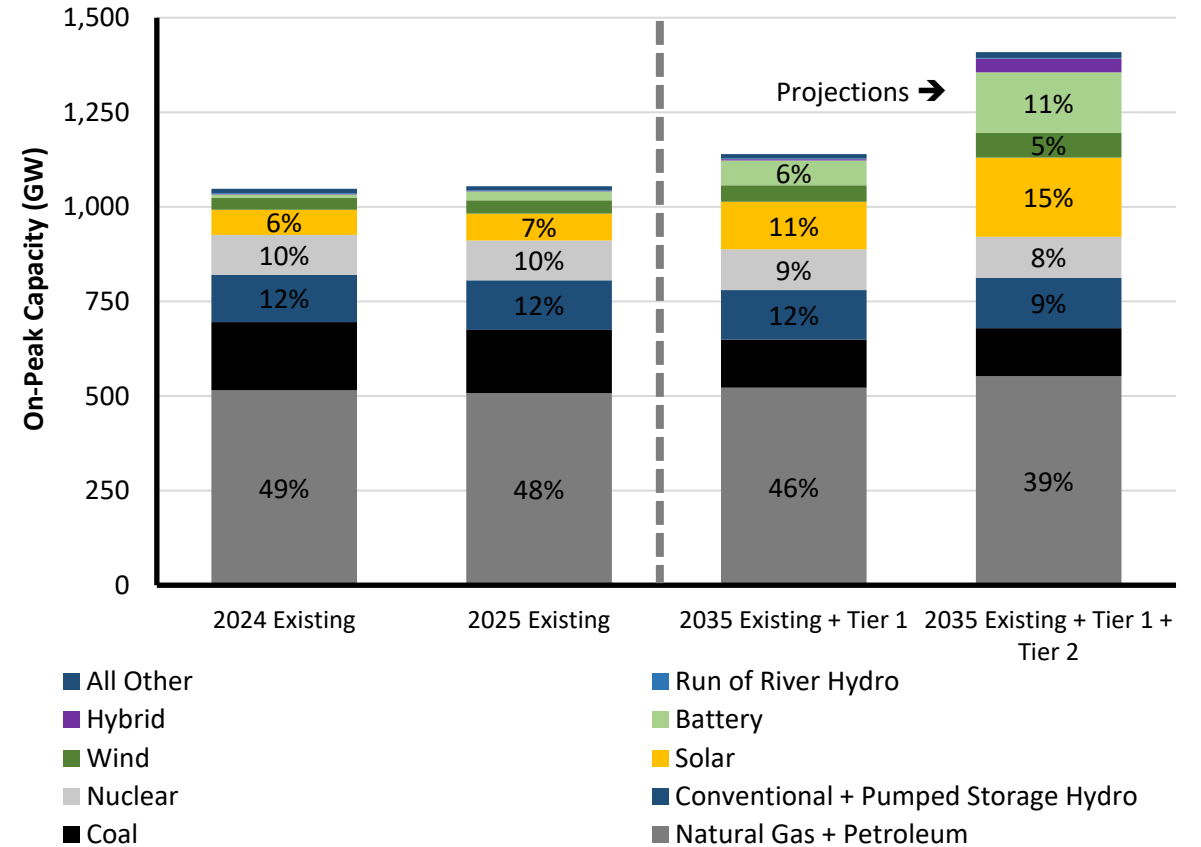


Figure 19: North America On-Peak Capacity Shares by Resource Type

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the 2025 LTRA, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in [Table 17](#).

Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT’s use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection’s response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The results of analysis for each Interconnection are in [Table 18](#). Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic

²⁵ [EIPC Frequency Response Report](#)

²⁶ 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

²⁷ ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was

studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia Studied	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	17.9% ²⁵	0	59.93 Hz	Low
Western Interconnection	42.9% ²⁶	0	59.65 Hz	Low
Texas Interconnection	65.7%	0	N/A	Low ²⁷
Québec Interconnection	37%	0	N/A	Low

Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation’s share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see [Figure 20](#)). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today’s energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection’s [Reliability Resource Initiative](#) has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO’s [ERAS](#) include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP’s *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

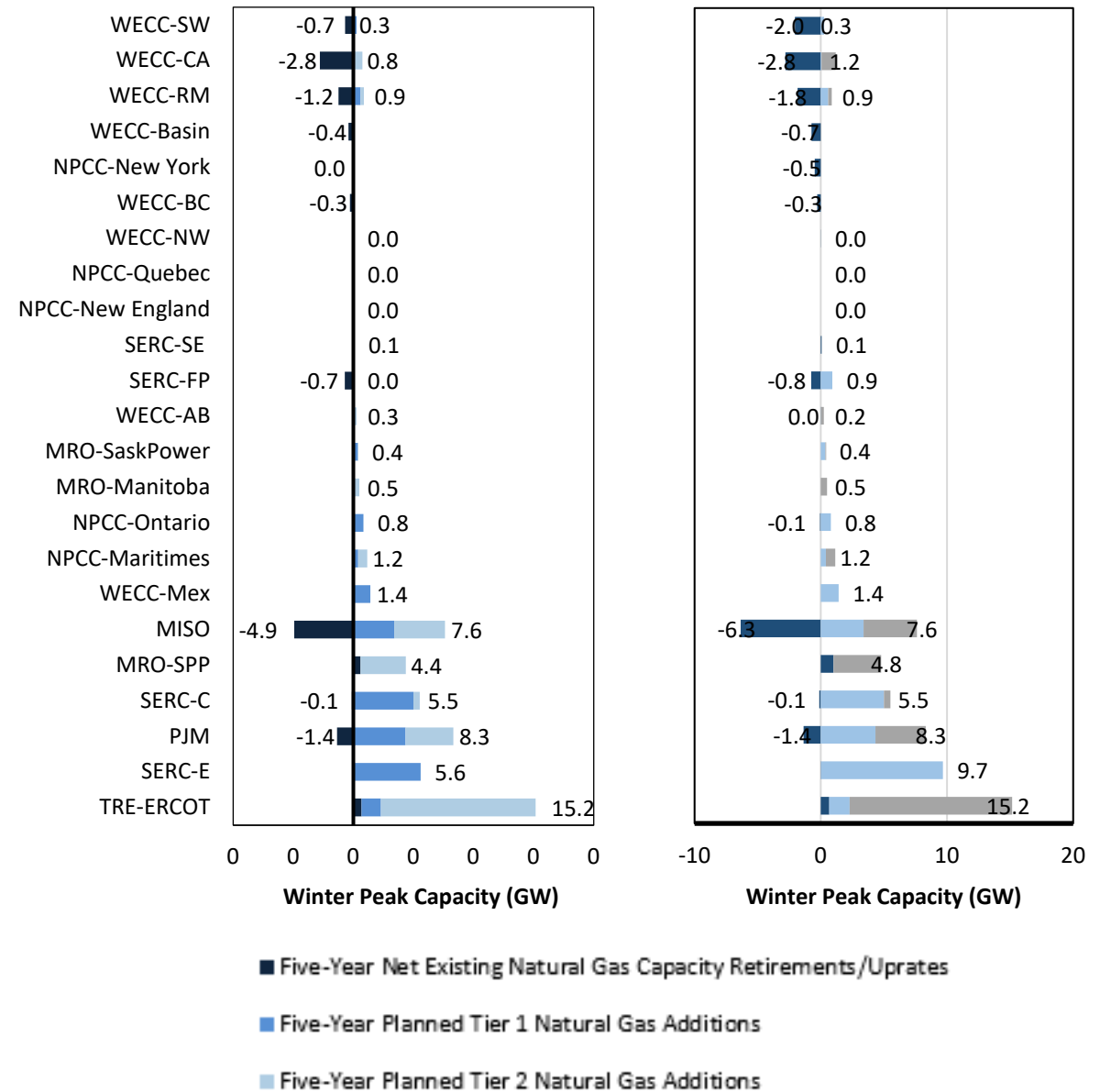


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers' supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

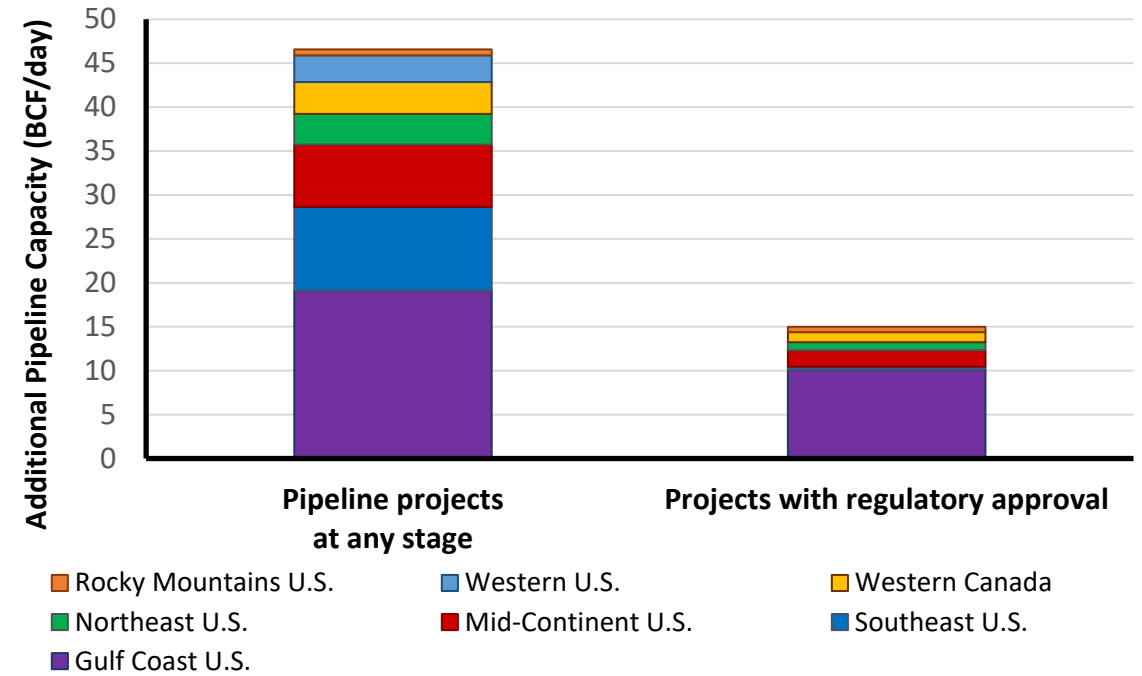


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

The nearly 40 GW of natural-gas-fired winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see Figure 22), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

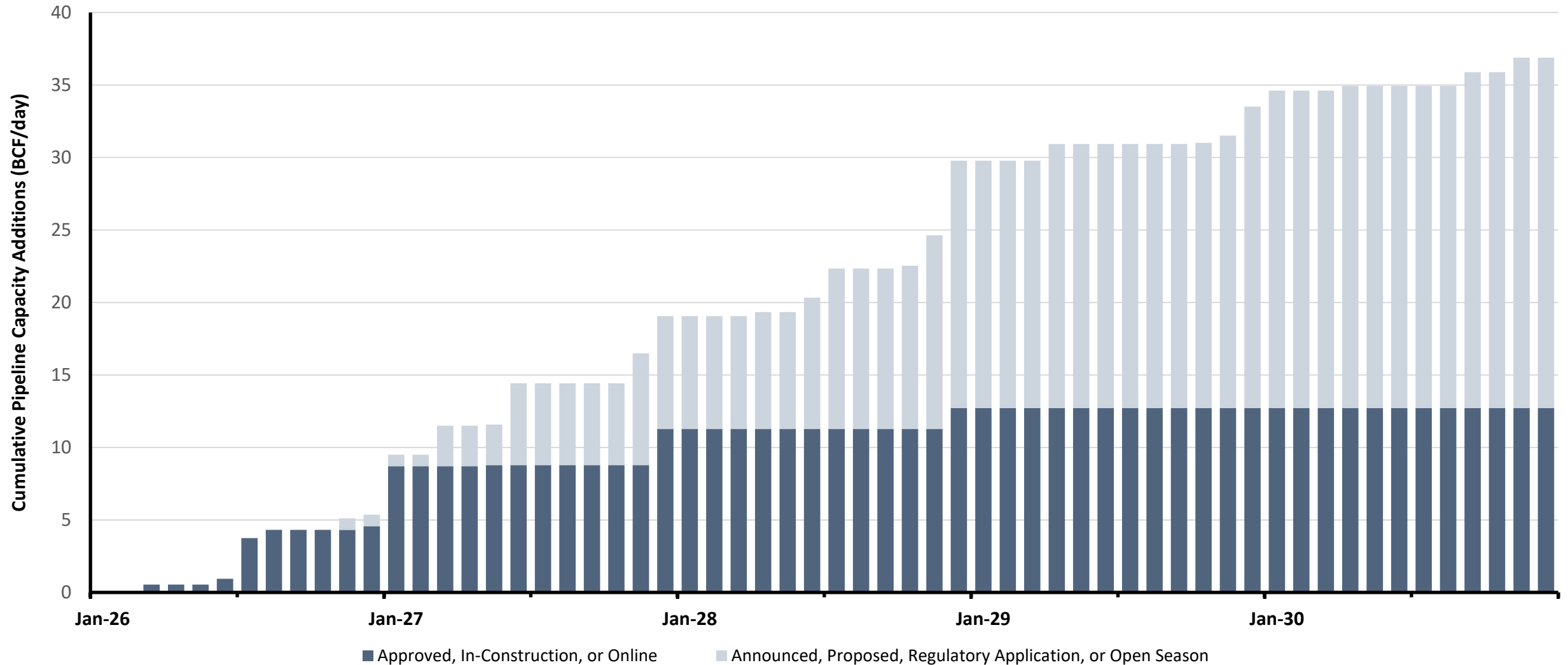


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year’s cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see [Figure 23](#)) is substantially higher than the 2024 LTRA 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

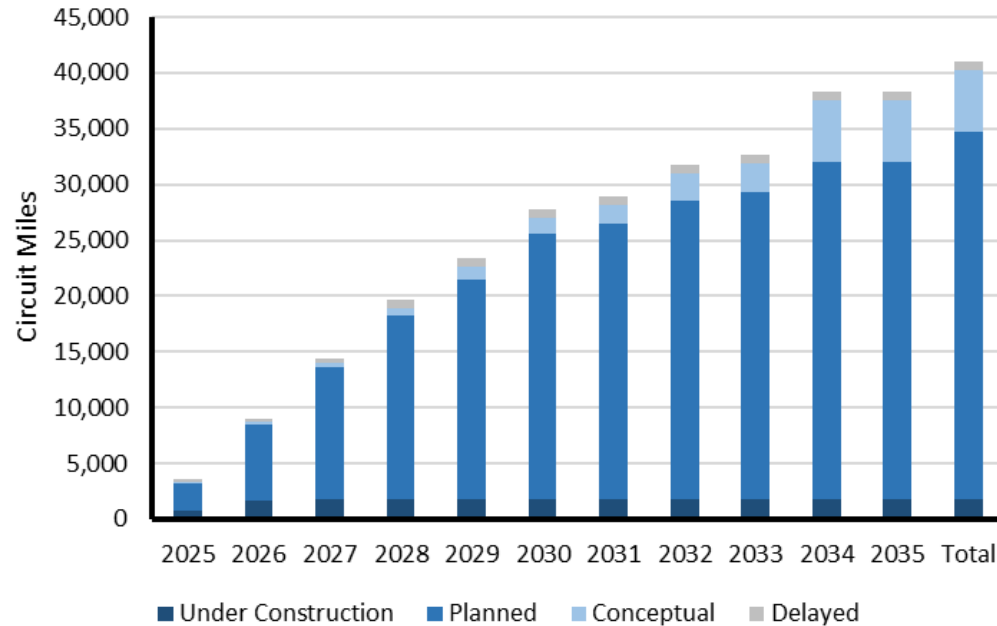


Figure 23: Future Transmission Circuit Miles > 100 kV by Project Status²⁸

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec’s plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to

²⁸ The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. [Figure 24](#) shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

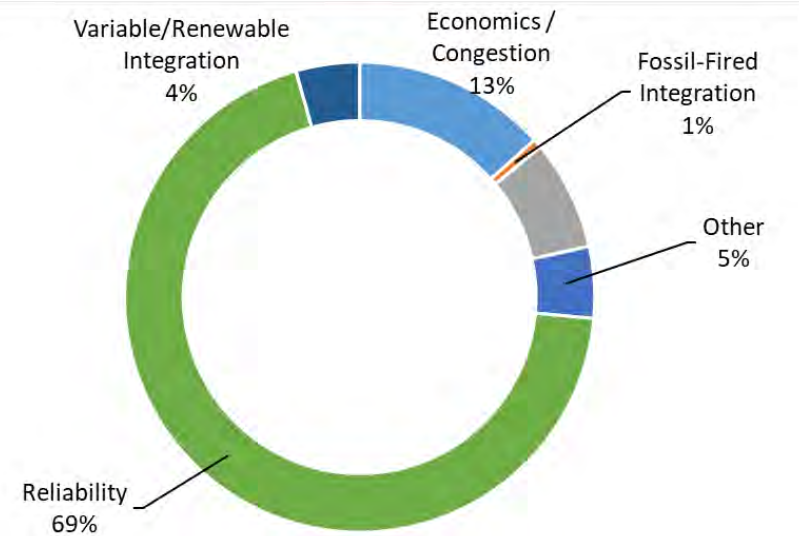


Figure 24: Future Transmission Circuit Miles by Primary Driver

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,²⁹ including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year’s LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalachies-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area’s pages (in the [Regional Assessments Dashboards](#)) for current transmission development details.

²⁹ [Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission](#)

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Interregional Transfer Capability Study (Canadian Analysis)

In the 2024 LTRA, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability³⁰ for U.S. transmission planning regions (TPR) that could support energy adequacy.³¹ NERC filed the completed study report with FERC on November 19, 2024.³² Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The [ITCS Canadian Analysis](#) (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in [Figure 25](#) and [Figure 26](#), respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR³³ but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

³⁰ Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

³¹ As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet

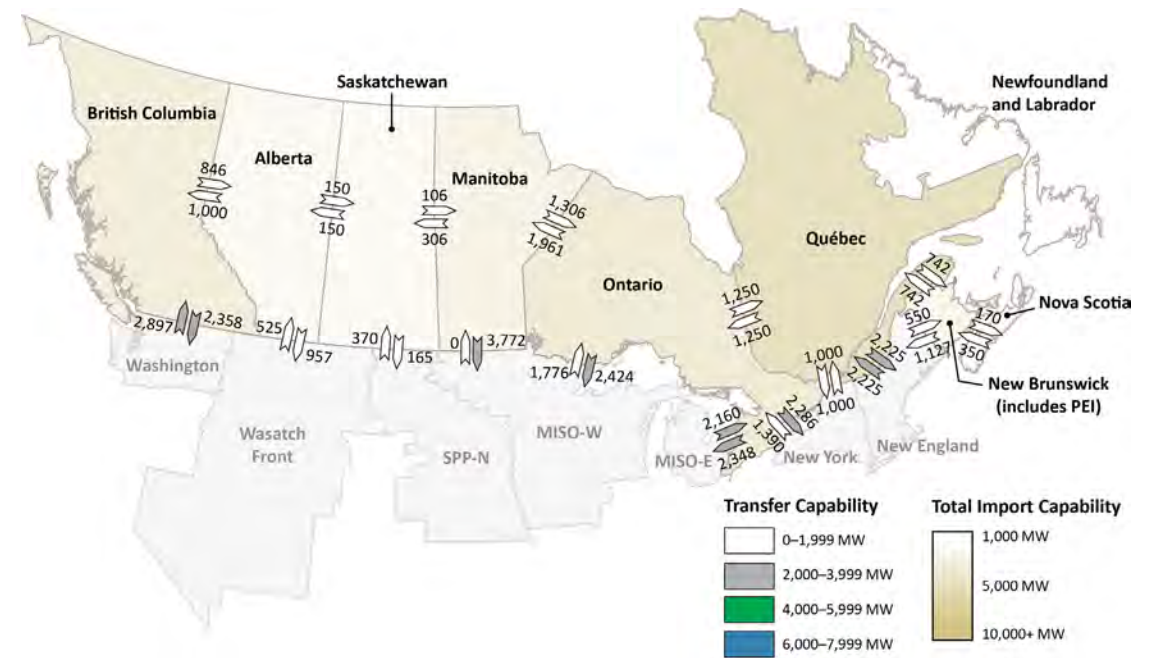


Figure 25: Transfer Capabilities (Summer)

customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

³² NERC [filing](#) of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

³³ Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

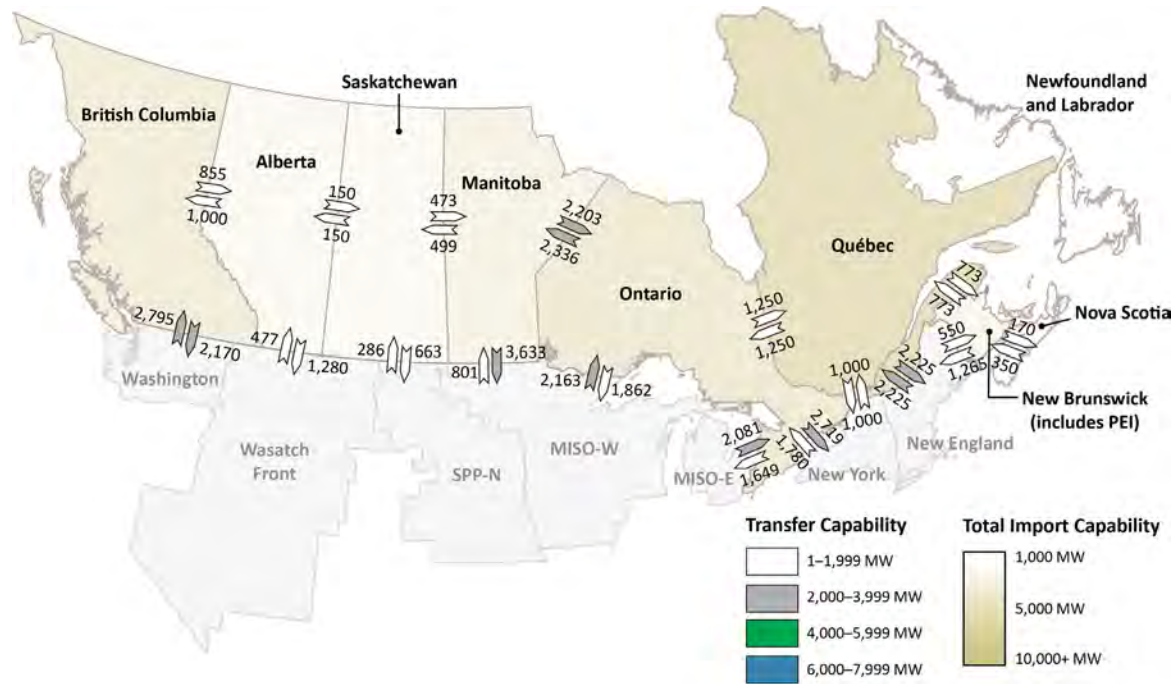


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.³⁴ Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the *2023 LTRA* using the current transfer capabilities.³⁵ The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC’s role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

³⁴ This study did not incorporate climate change models.

³⁵ The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in 2024 LTRA data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study’s assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province’s vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on 2023 LTRA data. A sensitivity study using more recent forecasts, based on 2024 LTRA data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. [Figure 27](#) shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

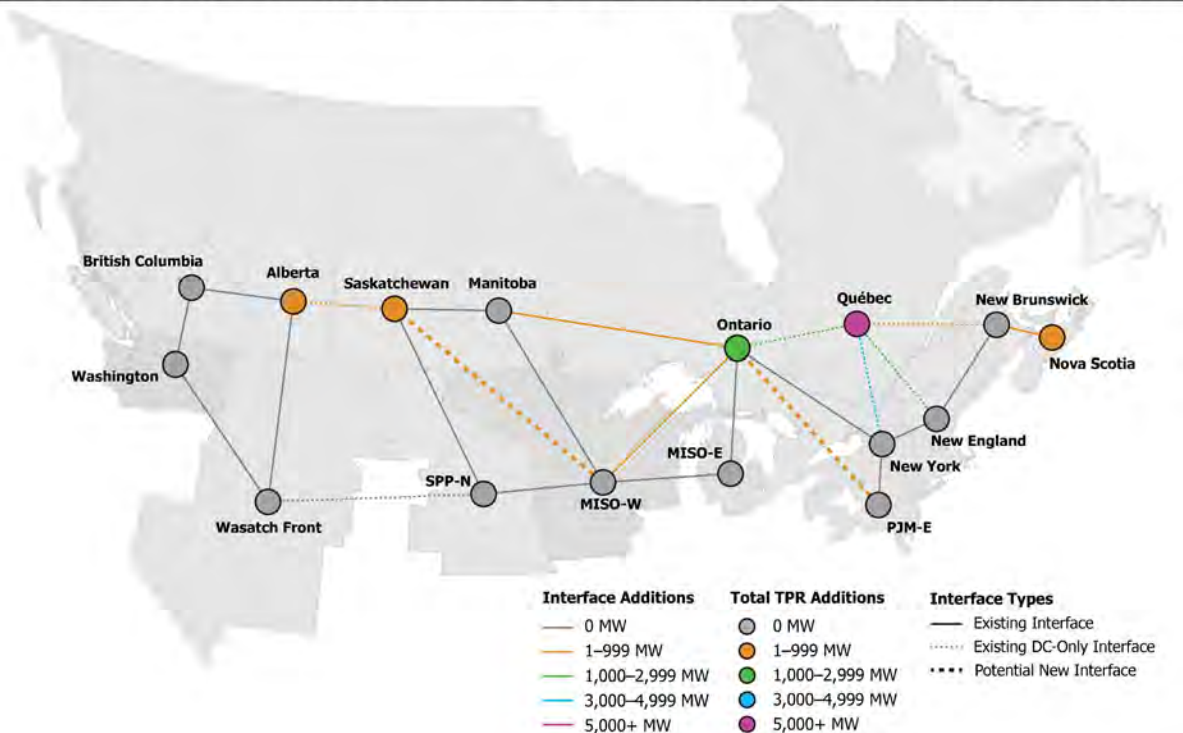
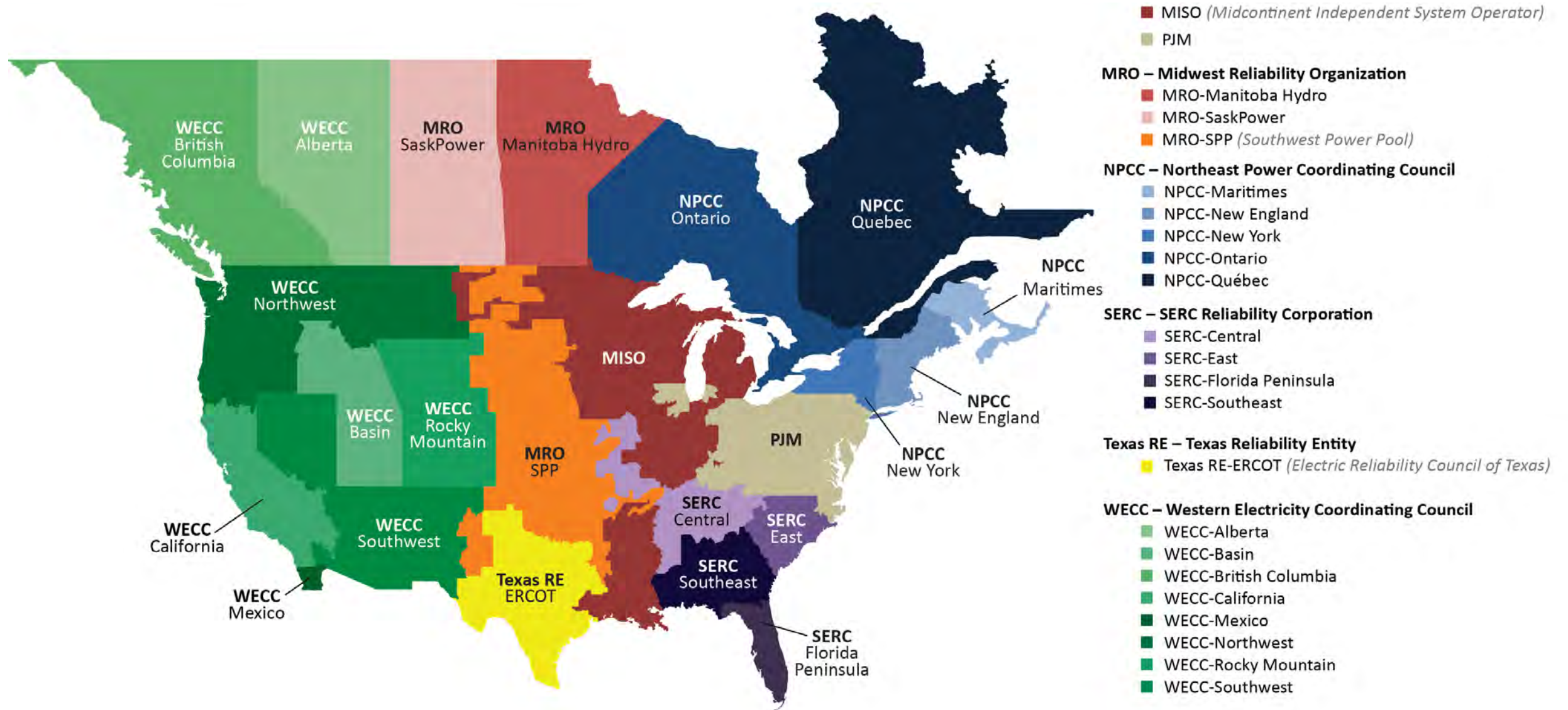


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



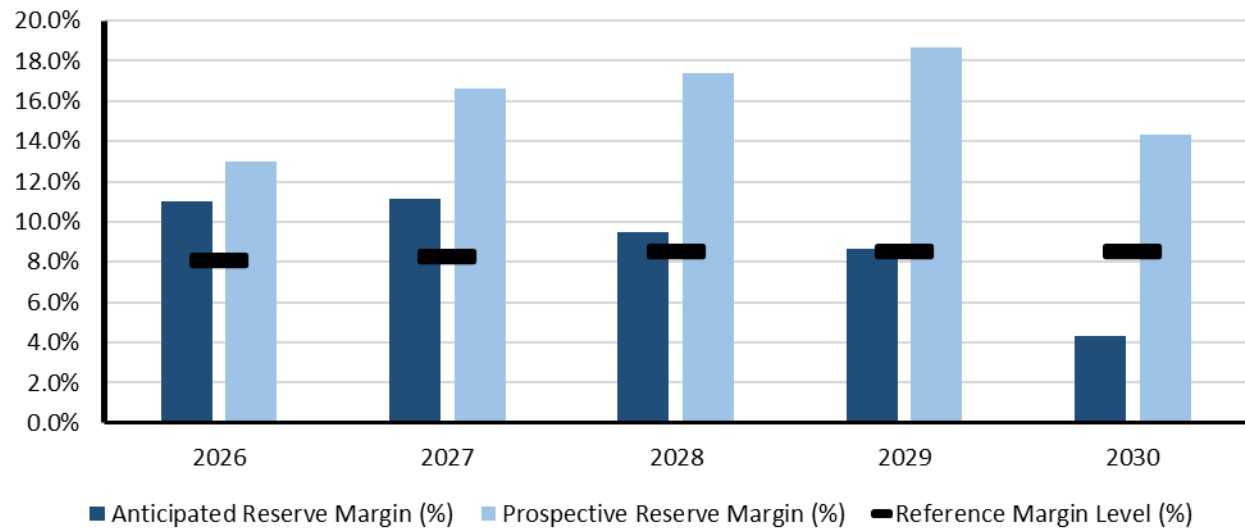


MISO

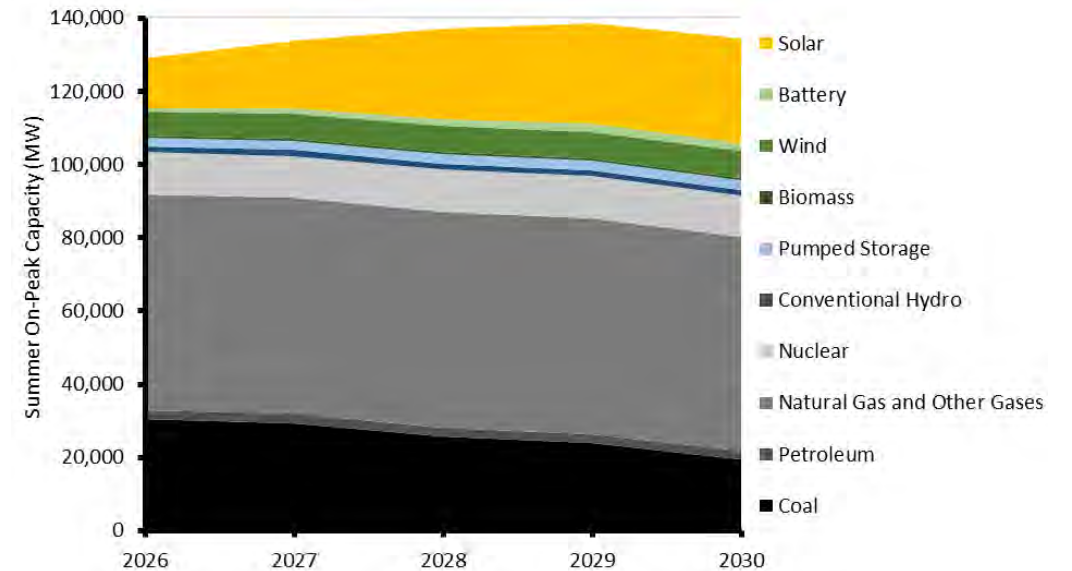
The Midcontinent Independent System Operator, Inc. ([MISO](#)) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world’s largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO’s footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



Planning Reserve Margins



Existing and Tier 1 Resources

MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year’s assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO’s accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest \$30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	30,442	29,376	25,620	23,780	19,384
Petroleum	2,551	2,551	2,551	2,551	2,428
Natural Gas	58,748	58,892	58,984	59,099	58,262
Biomass	585	580	516	515	512
Solar	13,586	18,496	24,792	27,499	28,629
Wind	6,576	6,757	7,139	7,258	7,379
Conventional Hydro	1,521	1,523	1,524	1,524	1,524
Pumped Storage	2,608	2,608	2,608	2,608	2,608
Nuclear	11,571	11,571	11,571	11,571	11,571
Other	68	68	68	68	63
Battery	774	1,462	1,950	2,243	2,243
Total MW	129,031	133,883	137,322	138,715	134,604

MISO Assessment

MISO's guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO's [Statement of Guiding Principles](#) for more information.

Planning Reserve Margins

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator's equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO's [LOLE Study for PY 2025–2026](#) estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body's purview, in which case a state-mandated PRM may be used in MISO's analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The [2025 OMS-MISO Survey](#) indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim [ERAS](#) process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
6. Enhance allocation of resource adequacy requirements.

Energy Risk

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO’s LOLE Study for PY 25–26, MISO has also performed additional assessments for [renewable integration](#) and [regional resource evolution](#) that touch on the topic of energy risk but are not a formal part of MISO’s resource adequacy and resource planning processes.

ProbA Results

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO’s system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO’s LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the

markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

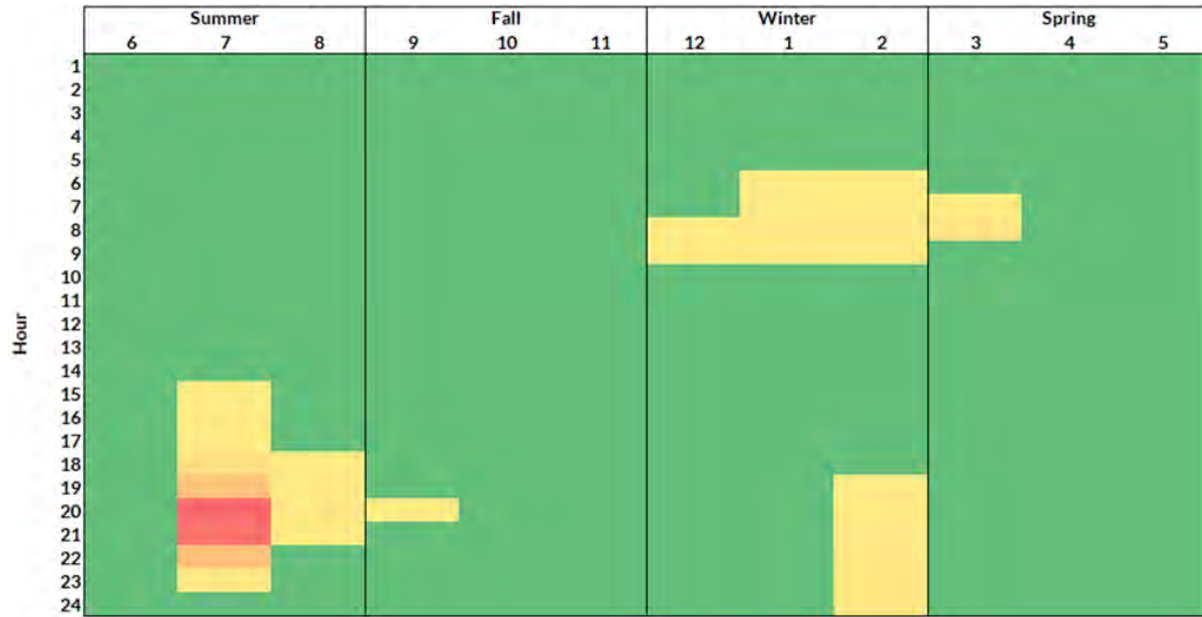
- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO’s annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

Base-Case Summary of Results			
	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

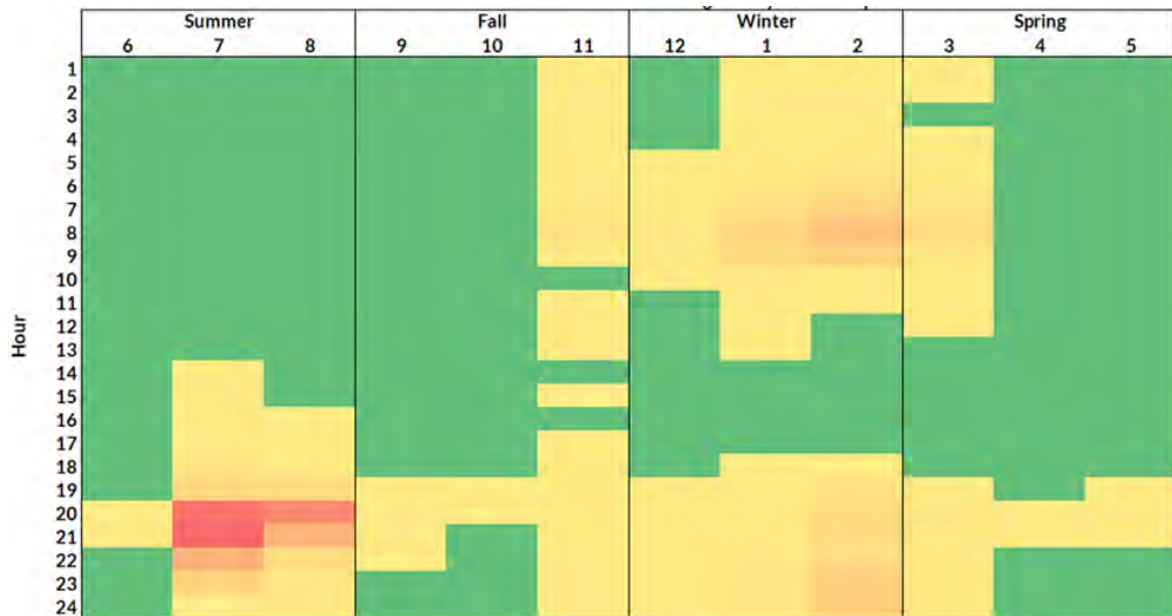
*Provides the 2024 ProbA Results for Comparison

**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.



2027-2028 ProbA Heat Map



2029-2030 ProbA Heat Map

Demand

LSEs within MISO’s footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the 2025 LTRA, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO’s normal process, the coincident peak demand forecast is used to determine each LSE’s PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the 2024 LTRA, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published [a Long-Term Load Forecast white paper](#) in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

Demand-Side Management

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO’s latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

Distributed Energy Resources

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO’s transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

Generation

Because of the size of MISO’s interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent [2025 OMS-MISO survey](#) used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA’s existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

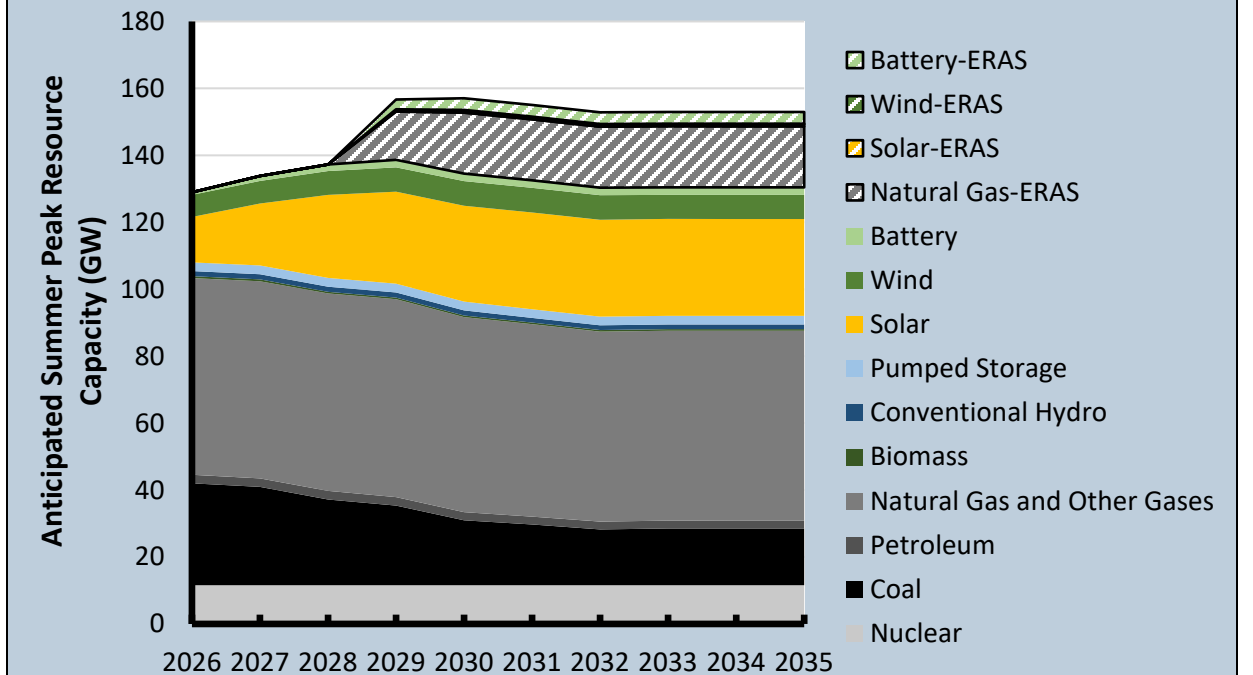
MISO’s accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

Energy Storage

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO’s anticipated installations include an addition of more than 2.4 GW by Summer 2030

and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO’s growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

The timing of FERC’s approval of MISO’s ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from the ERAS program is expected to grow to over 20 GW by Summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year’s ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the 2026 LTRA and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO’s ERAS Process on Anticipated Summer Capacity

Energy Transfers

In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO's probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

Transmission

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO's transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO's transmission expansion plan, see information and reports posted on MISO's [MTEP](#) page.

MISO has 488 transmission projects totaling \$30 billion planned across [MTEP24](#), its [Long Range Transmission Planning \(LRTP\)](#) Tranche 2.1, and the [SPP-MISO Joint Targeted Interconnection Queue \(JTIQ\)](#). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV

transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area's large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO's Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

Reliability Issues

Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

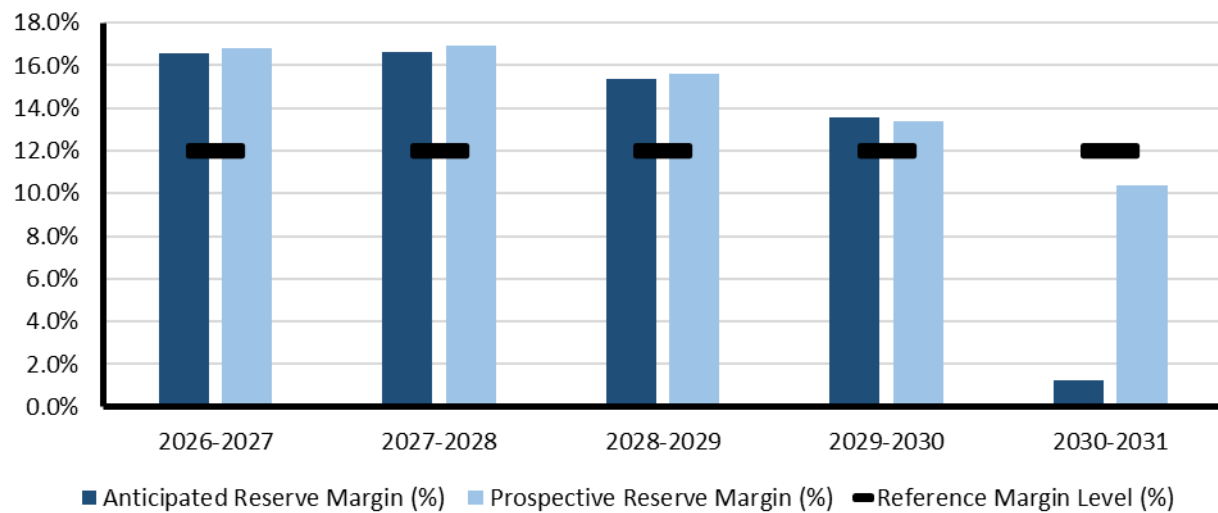


MRO-Manitoba Hydro

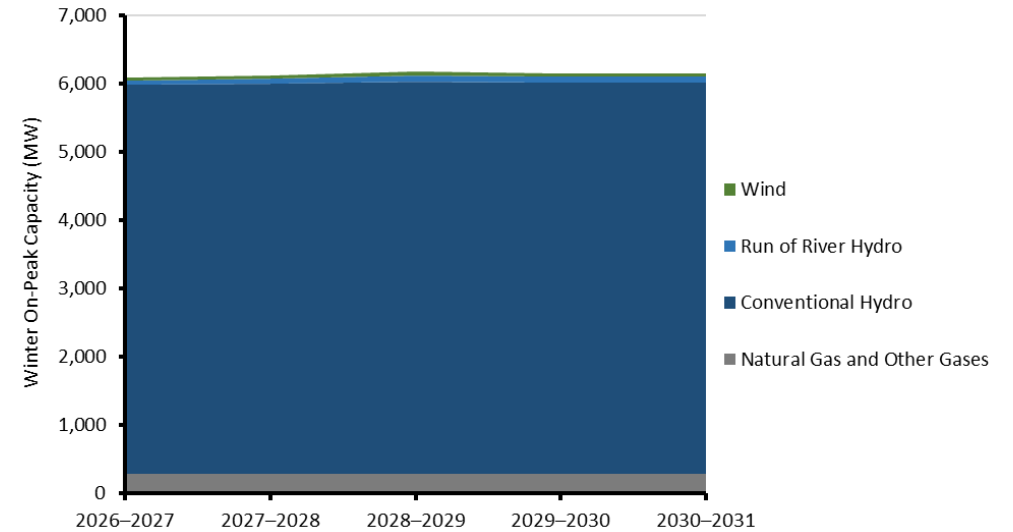
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Additions: Tier 1	36	50	63	63	63	63	63	63	63	63
Additions: Tier 2	0	0	0	0	500	500	500	500	500	500
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-93	-167	-172	-565	-565	-565	-565	-565	-315
Existing-Certain and Net Firm Transfers	5,794	5,831	5,799	5,770	5,377	5,377	5,377	5,377	5,377	5,627
Anticipated Reserve Margin (%)	16.6%	16.7%	15.4%	13.6%	1.2%	0.5%	-0.1%	-1.2%	-2.5%	0.6%
Prospective Reserve Margin (%)	16.8%	16.9%	15.6%	13.4%	10.4%	9.6%	8.9%	7.7%	6.3%	9.3%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.³⁶

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	278	278	278	278	278
Wind	52	52	52	52	52
Conventional Hydro	5,705	5,723	5,758	5,735	5,735
Run of River Hydro	59	71	90	90	90
Total MW	6,094	6,124	6,179	6,155	6,155

³⁶ [Province directs Manitoba Hydro to continue pause on new cryptocurrency connections](#)

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts (“diversity capacity”) in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

Demand

Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba’s winter peak. The pilot program is targeting to launch for the winter of 2025.

Energy Risk

As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessment (ProbA)

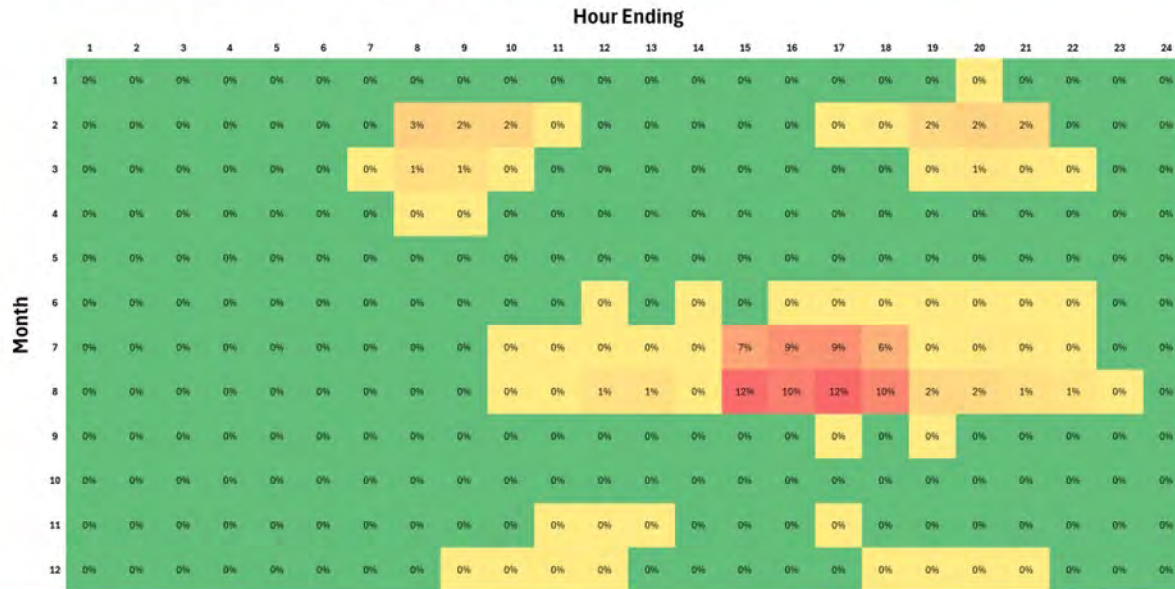
Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

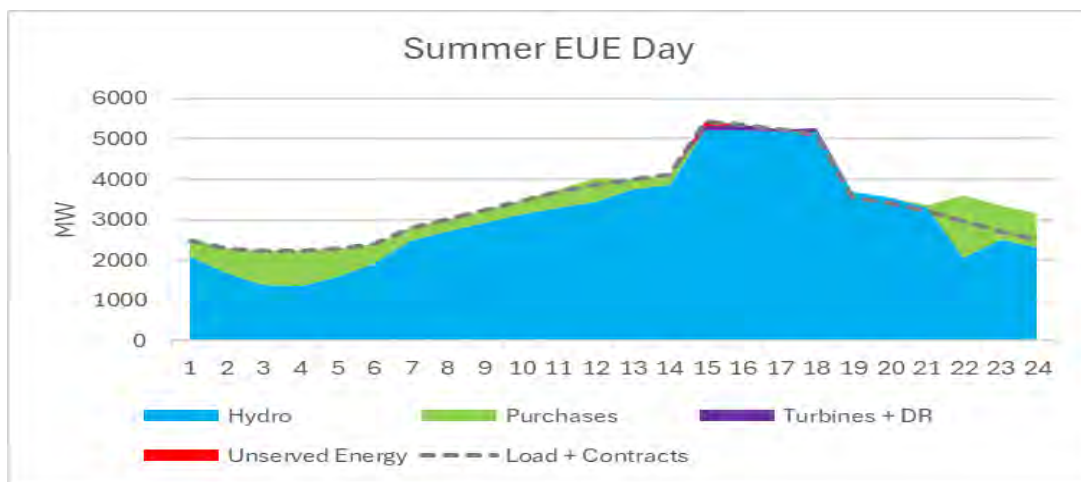
There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.

2029 EUE Heat Map



A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.



Distributed Energy Resources

There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DERs may be dependent on solar PV subsidies and/or incentives.

Generation

Under normal water conditions, over 95% of the generation in Manitoba Hydro’s system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an [Integrated Resource Plan](#) that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba’s electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro’s forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

Energy Storage

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

Energy Transfers

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts (“diversity capacity”) in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

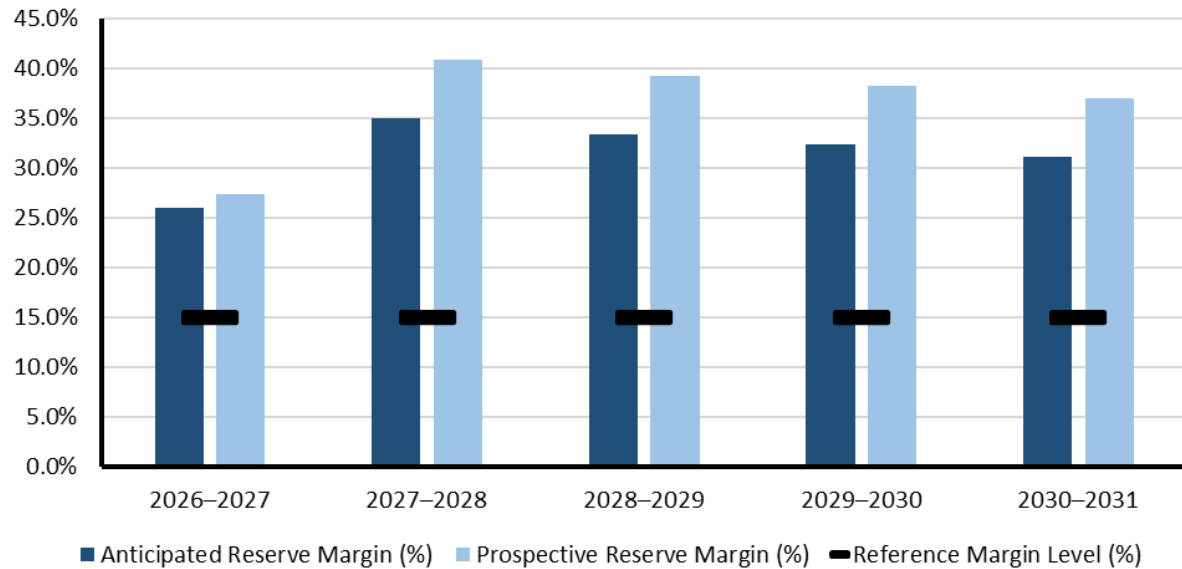


MRO-SaskPower

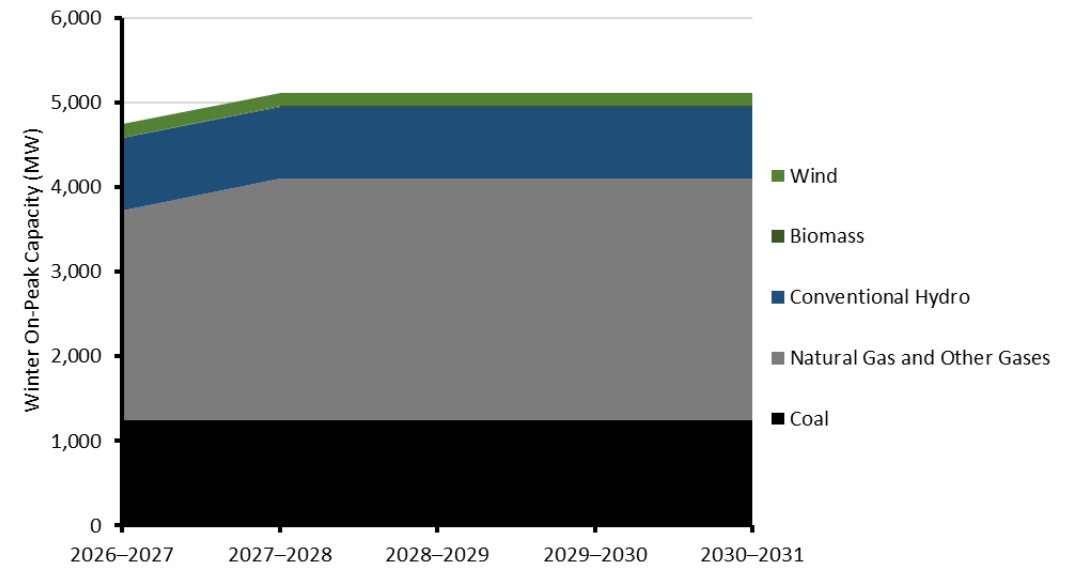
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	4,040	4,112	4,148	4,180	4,205	4,230	4,278	4,314	4,347	4,375
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,968	4,040	4,076	4,108	4,133	4,158	4,206	4,242	4,275	4,303
Additions: Tier 1	90	460	460	460	460	460	460	460	460	460
Additions: Tier 2	55	241	241	241	241	241	241	241	241	241
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,907	4,992	4,976	4,976	4,961	4,962	4,900	4,962	4,976	4,892
Anticipated Reserve Margin (%)	25.9%	35.0%	33.4%	32.3%	31.2%	30.4%	27.4%	27.8%	27.2%	24.4%
Prospective Reserve Margin (%)	27.3%	40.9%	39.3%	38.2%	37.0%	35.5%	32.5%	32.8%	32.1%	29.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower’s ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower’s recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan’s average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower’s forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower’s primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan’s power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan’s gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,249	1,249	1,249	1,249	1,249
Natural Gas	2,480	2,850	2,850	2,850	2,850
Biomass	3	3	3	3	3
Wind	164	162	162	162	162
Conventional Hydro	856	856	856	856	856
Other	17	17	1	1	1
Total MW	4,769	5,137	5,121	5,121	5,121

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan’s ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

Energy Assessment, Including Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area’s resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

ProbA Results

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

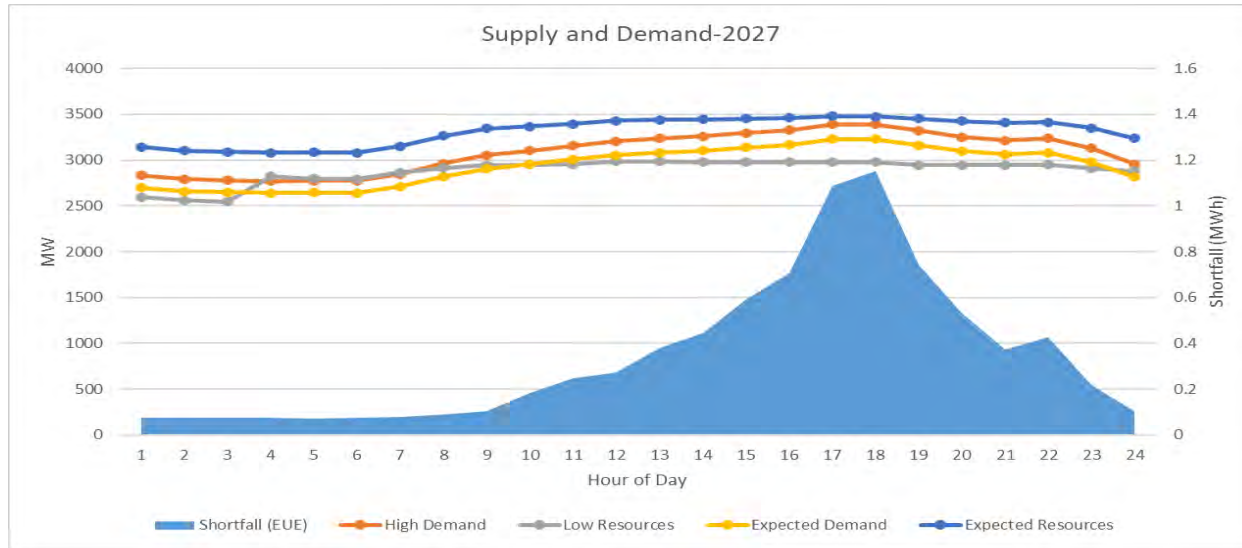
The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
* Provides the 2024 ProbA Results for Comparison			

The annual EUE heat map for 2027 is provided below.

Hourly EUE Heat Map : 2027																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Feb-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%
Mar-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May-27	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	4%	5%	5%	3%	3%	2%	3%	2%	1%
Jun-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Aug-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	0%	0%
Sep-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Oct-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Nov-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.



Demand

Saskatchewan experiences its peak season in the winter. Saskatchewan’s system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the 2024 LTRA’s projection of 1.35% average annual peak demand growth.

Demand-Side Management

Saskatchewan’s DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours’ notification, but those loads are not included in PRM calculations.

Distributed Energy Resources

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An

additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

Generation

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province’s future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

Energy Storage

SaskPower’s first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

Energy Transfers

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower's emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC's [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower's Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan's remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

Reliability Issues

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system

components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan's power generation and natural gas production. Saskatchewan's pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

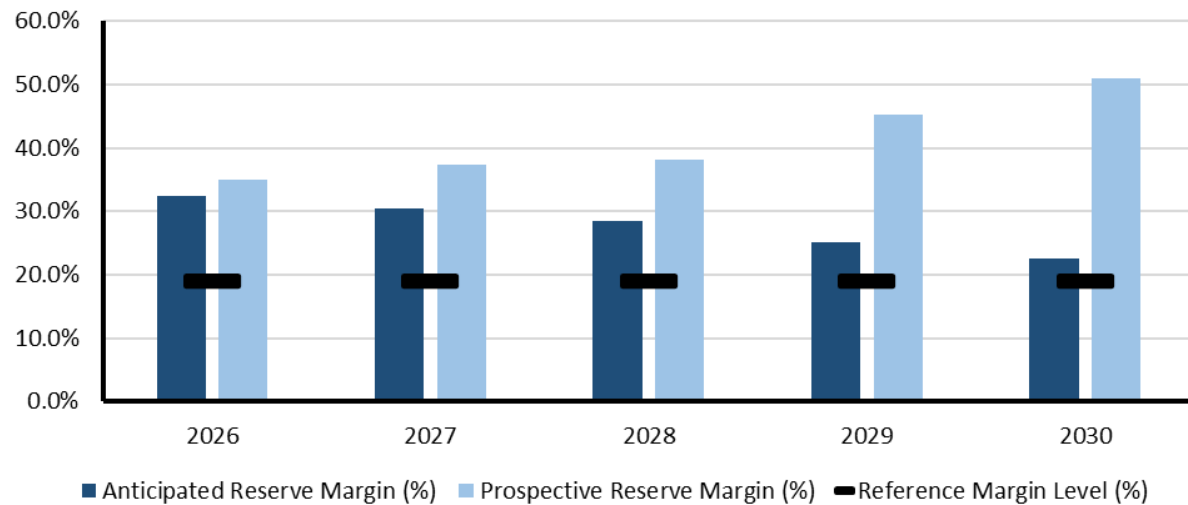


MRO-SPP

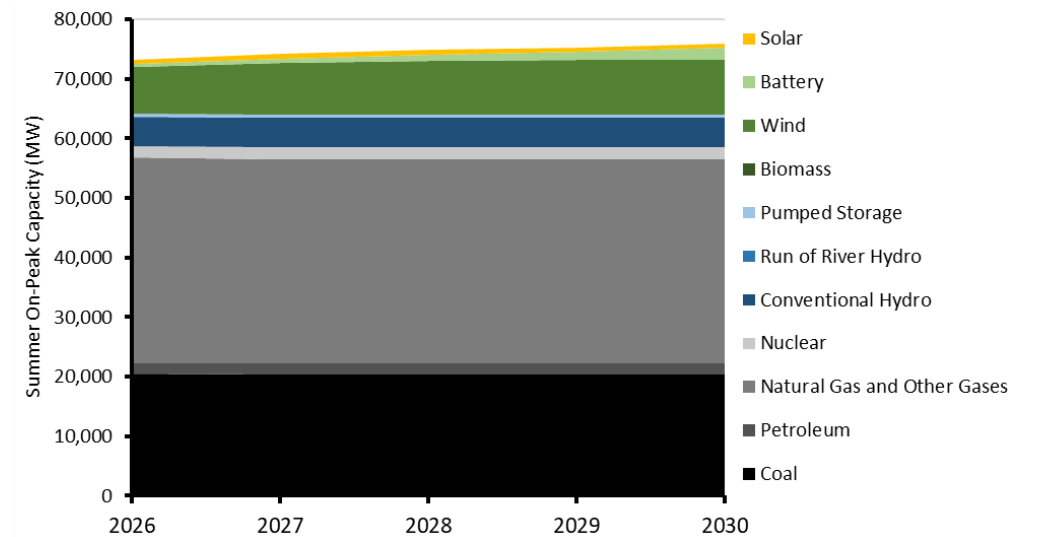
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	57,479	59,121	60,689	62,766	64,475	66,283	66,982	67,570	68,049	68,622
Demand Response	2,138	2,162	2,332	2,508	2,509	2,511	2,513	2,514	2,718	2,720
Net Internal Demand	55,340	56,959	58,357	60,258	61,966	63,772	64,469	65,056	65,331	65,902
Additions: Tier 1	1,808	3,020	3,685	4,251	4,815	4,866	5,344	5,344	5,344	5,344
Additions: Tier 2	2,436	6,104	8,948	15,659	21,487	23,345	25,664	27,277	27,877	28,627
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-18	-78	-78	-78	-78	-79	-79	-79	-79	-79
Existing-Certain and Net Firm Transfers	71,475	71,224	71,232	71,127	71,146	71,115	71,135	71,106	71,105	71,106
Anticipated Reserve Margin (%)	32.4%	30.3%	28.4%	25.1%	22.6%	19.1%	18.6%	17.5%	17.0%	16.0%
Prospective Reserve Margin (%)	34.9%	37.3%	38.2%	45.2%	50.9%	48.7%	51.5%	51.8%	51.8%	50.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	20,473	20,440	20,440	20,428	20,428
Coal*	19,187	19,154	18,086	18,075	18,075
Petroleum	1,824	1,827	1,827	1,827	1,829
Petroleum*	1,824	1,771	1,771	1,771	1,774
Natural Gas	34,525	34,303	34,303	34,265	34,265
Natural Gas*	34,363	33,662	33,550	33,512	33,268
Biomass	35	35	35	35	35
Solar	700	700	700	700	700
Wind	7,831	8,581	9,044	9,134	9,191
Conventional Hydro	4,925	4,993	5,009	5,026	5,030
Pumped Storage	456	456	456	415	460
Nuclear	1,945	1,945	1,945	1,945	1,945
Other	281	281	281	281	281
Battery	379	833	1,027	1,472	1,949
Total MW	73,429	74,450	75,123	75,584	76,168
Total MW*	71,981	72,467	71,960	72,422	72,762

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.

MRO-SPP Assessment

Planning Reserve Margins

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the 2025 LTRA as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP’s 2023 LOLE study supported much of the demand forecast presented in NERC’s 2024 LTRA and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO’s Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

ProbA Results

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP’s LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP’s LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

Demand

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP’s energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

Demand-Side Management

SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP's tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

Generation

In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the 2024 LTRA, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP's Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP's Tier 2 queue since

July and are not reflected in this year's LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC's reliability assessments and ProbA and count toward ARM.

Energy Storage

There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

Capacity Transfers

Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

Transmission

SPP's [2024 Integrated Transmission Plan \(ITP\)](#) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

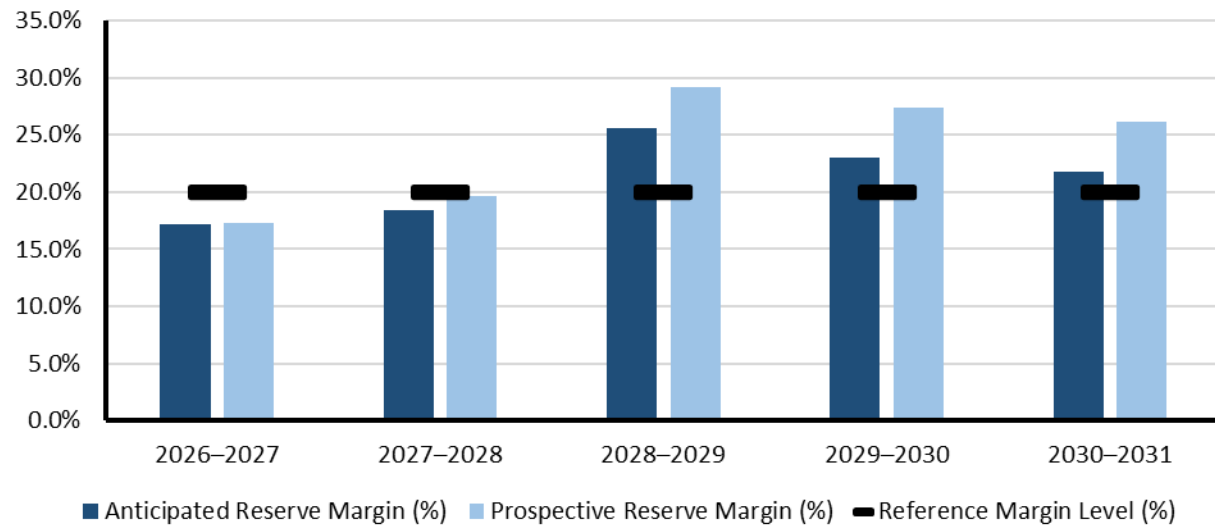


NPCC-Maritimes

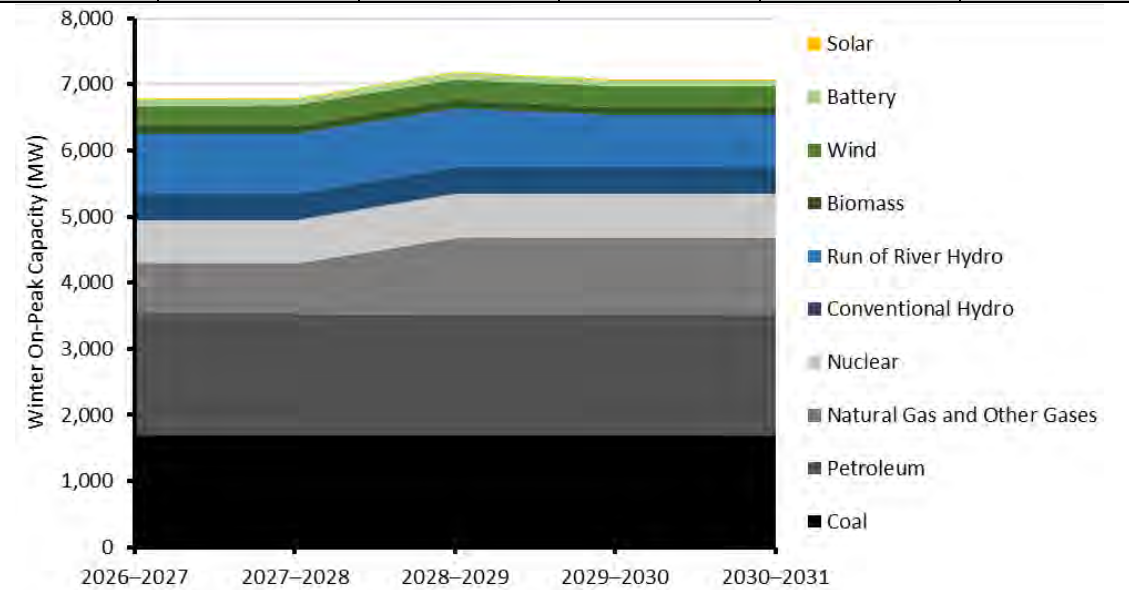
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power’s system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	6,107	6,157	6,194	6,231	6,292	6,346	6,380	6,493	6,579	6,669
Demand Response	264	283	290	291	290	291	290	291	290	290
Net Internal Demand	5,843	5,875	5,904	5,940	6,001	6,055	6,089	6,202	6,289	6,380
Additions: Tier 1	173	179	579	579	579	579	579	579	579	579
Additions: Tier 2	6	367	656	1,492	1,492	1,492	1,492	1,492	1,492	1,492
Additions: Tier 3	0	0	23	101	215	227	239	251	260	260
Net Firm Capacity Transfers	-32	75	145	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,673	6,780	6,838	6,727	6,727	6,727	6,621	6,621	6,596	6,707
Anticipated Reserve Margin (%)	17.2%	18.5%	25.6%	23.0%	21.7%	20.7%	18.2%	16.1%	14.1%	14.2%
Prospective Reserve Margin (%)	17.3%	19.6%	29.2%	27.4%	26.1%	25.0%	22.6%	20.3%	18.3%	18.3%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Maritimes Highlights

- Since the 2024 LTRA, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year's projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,410	1,003	691
Petroleum	1,831	1,831	1,820	1,820	1,820
Natural Gas	757	757	1,157	1,157	1,157
Biomass	129	129	129	129	129
Solar	10	10	10	10	10
Wind	300	306	306	306	306
Conventional Hydro	395	395	395	395	395
Run of River Hydro	901	901	901	790	790
Nuclear	663	663	671	671	671
Other	98	98	89	89	89
Battery	99	99	99	99	99
Total MW	6,878	6,884	7,272	7,161	7,161
Total MW*	6,878	6,884	6,986	6,468	6,156

* Capacity with additional generator retirements. Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.

NPCC-Maritimes Assessment

Planning Reserve Margins

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two BAs within the Maritimes area, as members of the NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Energy Risk

During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two Balancing Authorities within the Maritimes Area as members of the Northeast Power Coordinating Council (NPCC) jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual and seasonal ProbAs, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

ProbA

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	5	15	7
NEUE (ppm)	0.17	0.52	0.25
LOLH (hours/year)	0.09	0.25	0.10

*Results from the 2024 ProbA simulations

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the 2024 LTRA, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

Demand-Side Management

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW.³⁷ The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

Distributed Energy Resources

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

Generation

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program

³⁷ Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized

(2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026–2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029–2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the 2025 LTRA submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Capacity Transfers

Probabilistic studies show that Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



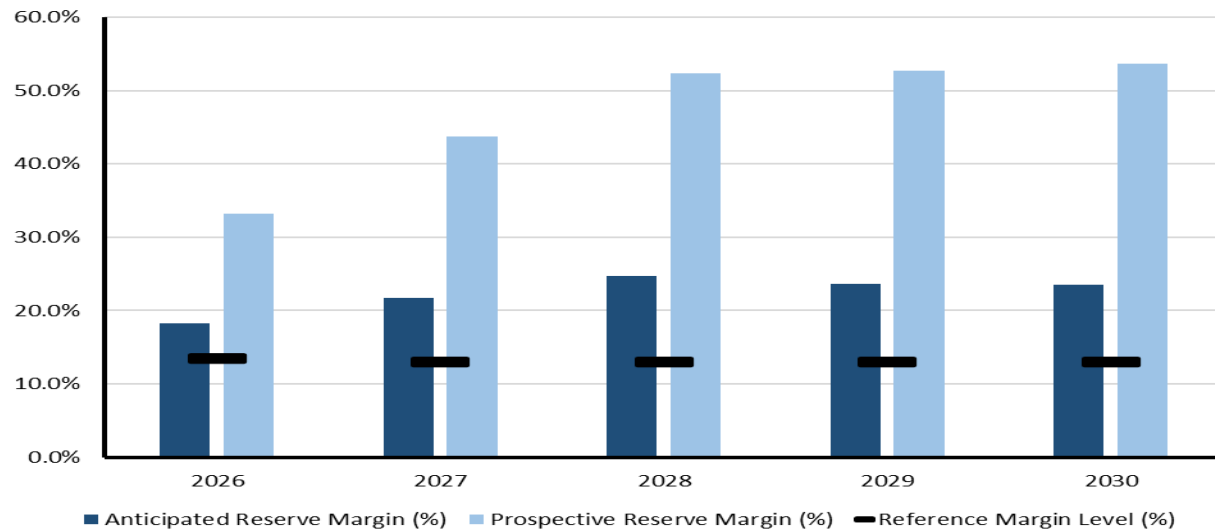
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

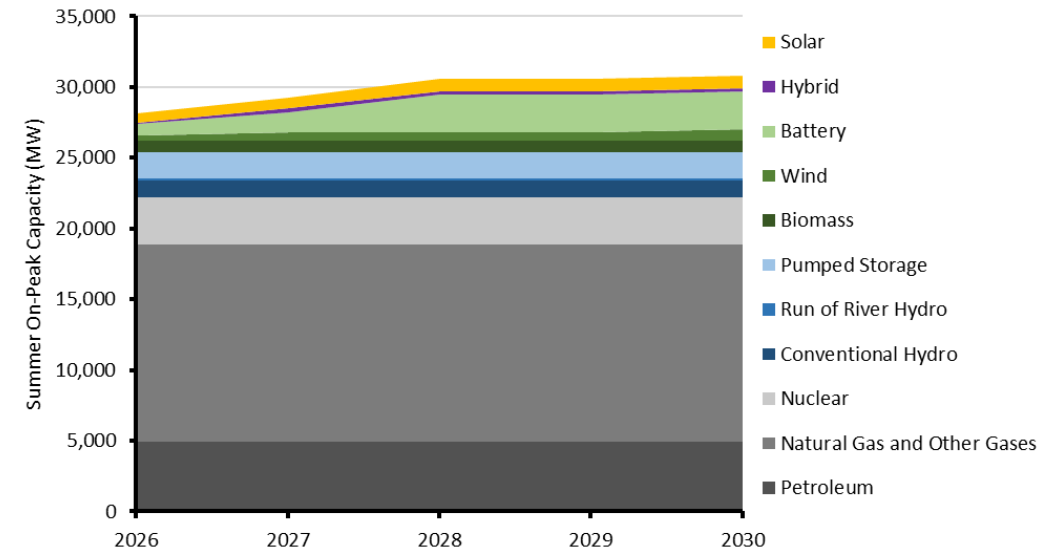
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	24,877	24,945	25,124	25,347	25,557	25,821	26,123	26,486	26,897	27,331
Demand Response	623	544	544	544	544	544	544	544	544	544
Net Internal Demand	24,254	24,401	24,580	24,803	25,013	25,277	25,579	25,942	26,353	26,787
Additions: Tier 1	1,081	2,183	3,543	3,551	3,781	3,781	3,913	3,913	4,263	4,263
Additions: Tier 2	1,113	2,871	4,274	4,687	5,037	5,037	5,037	5,387	5,387	5,387
Additions: Tier 3	872	4,129	10,335	11,426	11,830	12,924	12,924	12,924	12,924	12,924
Net Firm Capacity Transfers	567	465	84	84	84	84	84	0	0	0
Existing-Certain and Net Firm Transfers	27,607	27,505	27,124	27,124	27,124	27,124	27,124	27,040	27,040	27,040
Anticipated Reserve Margin (%)	18.3%	21.7%	24.8%	23.7%	23.6%	22.3%	21.3%	19.3%	18.8%	16.9%
Prospective Reserve Margin (%)	33.2%	43.7%	52.3%	52.7%	53.7%	52.1%	50.8%	49.7%	48.7%	46.3%
Reference Margin Level (%)	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the [New England Clean Energy Connect](#)) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW) ³⁸					
	2026	2027	2028	2029	2030
Petroleum	4,899	4,899	4,899	4,899	4,899
Natural Gas	13,939	13,939	13,939	13,939	13,939
Biomass	776	776	776	776	776
Solar	645	726	864	872	872
Wind	416	622	622	622	852
Conventional Hydro	1,165	1,165	1,165	1,165	1,165
Run of River Hydro	179	179	179	179	179
Pumped Storage	1,864	1,864	1,864	1,864	1,864
Nuclear	3,351	3,351	3,351	3,351	3,351
Hybrid	96	287	287	287	287
Battery	791	1,416	2,638	2,638	2,638
Total MW	28,121	29,223	30,584	30,591	30,821

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

³⁸ MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

Planning Reserve Margins

ISO-NE’s installed capacity requirement (ICR) is based on the capacity needed to meet NPCC’s resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

Energy Risks (Including Non-Peak Hour Risk)

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.

- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

Probabilistic Assessments (ProbA and Other Studies)

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states’ policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

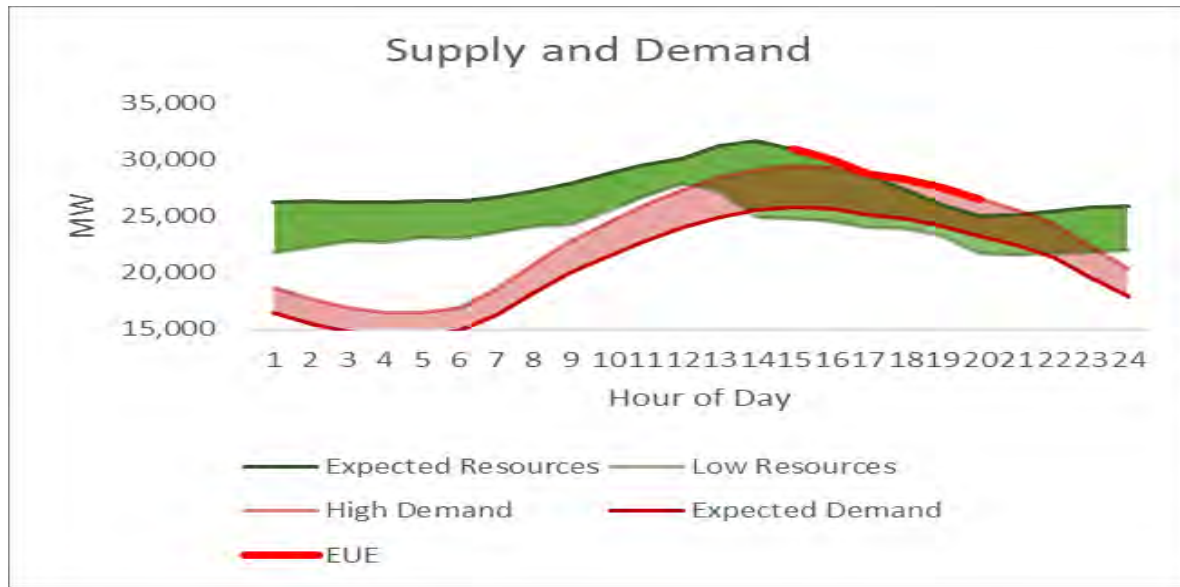
NPCC New England Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

EUE Heat Map – 2029

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

Month	Hour																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	10%	33%	24%	1%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	19%	5%	0%	0%	0%	0%	0%	
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
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2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.



Demand

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the 2024 LTRA. The energy growth projection has decreased as well since the 2024 LTRA.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England’s transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new [Planning Procedure 12](#) entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

Generation

The two largest changes that will impact New England’s generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the [Capacity Auction Reforms Key Project](#).

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

Energy Storage

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

Capacity Transfers (Reliance on Assistance)

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE’s firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the 2025 LTRA Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New

England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE’s longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

Reliability Issues

New England’s power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected “in-service” dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator’s fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- [Capacity Auction Reforms](#)
- [Operational Impacts of Extreme Weather Events](#)
- [Day-Ahead Ancillary Services Initiative](#)
- [2024 Economic Study](#)
- [Extended-Term Transmission Planning Tariff Changes](#) (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- [Longer-Term Transmission Studies](#)
- [Storage As Transmission Only Asset](#)
- [FERC Order No. 1920 Project](#)
- [FERC Order No. 2023 Project](#)
- [FERC Order No. 2222 Project](#)

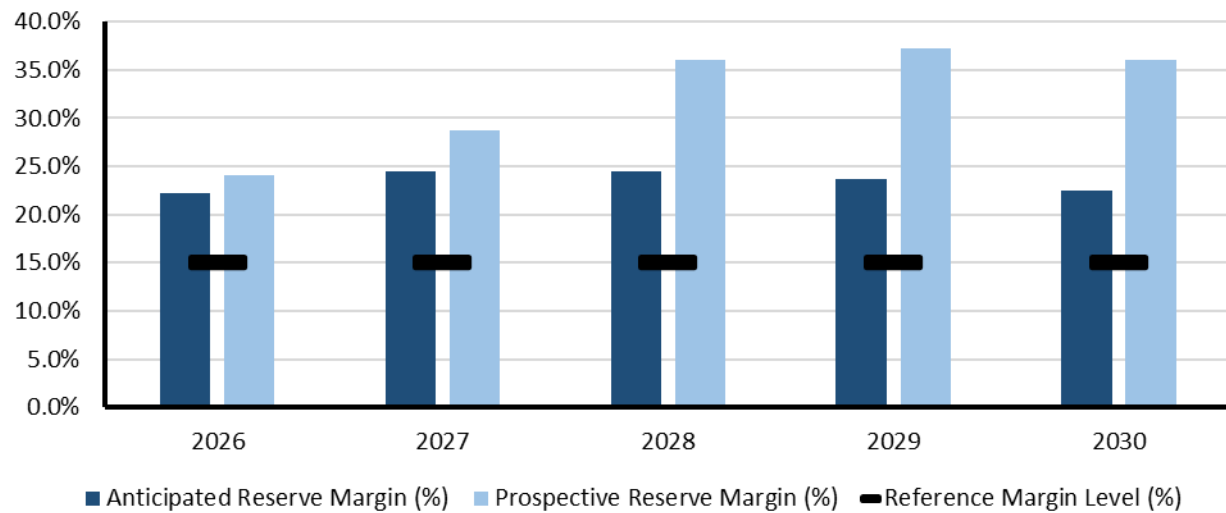


NPCC-New York

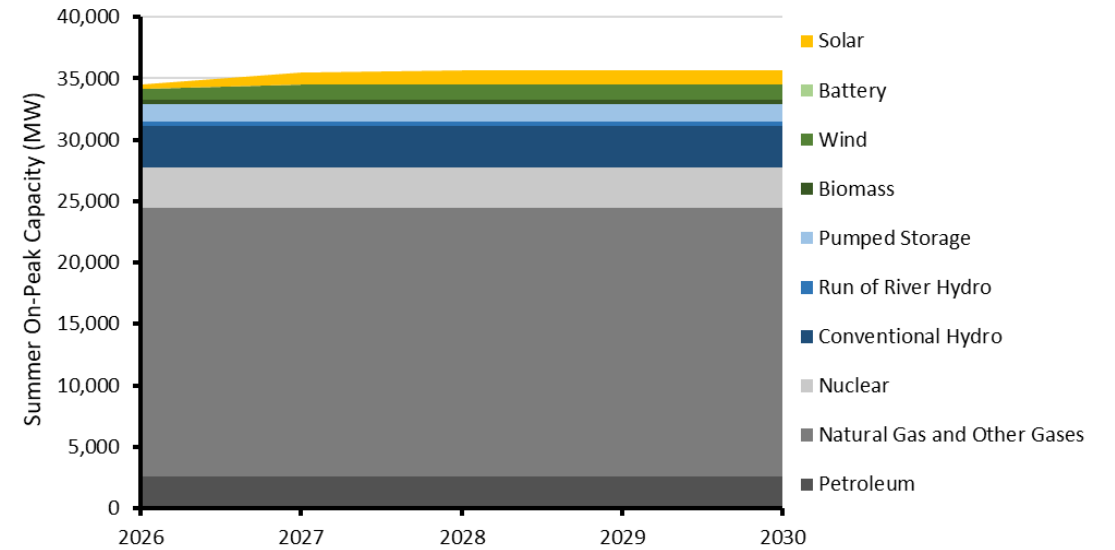
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York’s BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	31,990	32,280	32,410	32,620	32,910	33,190	33,520	33,870	34,170	34,500
Demand Response	989	989	989	989	989	989	989	989	989	989
Net Internal Demand	31,001	31,291	31,421	31,631	31,921	32,201	32,531	32,881	33,181	33,511
Additions: Tier 1	532	1,509	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660
Additions: Tier 2	574	1,317	3,642	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Additions: Tier 3	150	1,516	9,280	19,034	25,847	28,035	28,035	28,526	29,009	29,009
Net Firm Capacity Transfers	3,405	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486
Existing-Certain and Net Firm Transfers	37,368	37,449	37,450	37,450	37,450	36,995	36,995	36,995	36,995	36,995
Anticipated Reserve Margin (%)	22.3%	24.5%	24.5%	23.6%	22.5%	20.0%	18.8%	17.6%	16.5%	15.4%
Prospective Reserve Margin (%)	24.1%	28.7%	36.1%	37.3%	36.0%	33.4%	32.1%	30.7%	29.5%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO’s interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO’s 2025 Quarter 3 Short-Term Assessment of Reliability (STAR)³⁹ report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	2,597	2,597	2,597	2,597	2,597
Natural Gas	21,858	21,858	21,858	21,858	21,858
Biomass	334	334	334	334	334
Solar	345	931	1,083	1,083	1,083
Wind	850	1,221	1,221	1,221	1,221
Geothermal	0	0	0	0	0
Conventional Hydro	3,324	3,324	3,324	3,324	3,324
Run of River Hydro	418	418	418	418	418
Pumped Storage	1,411	1,411	1,411	1,411	1,411
Nuclear	3,326	3,326	3,326	3,326	3,326
Hybrid	0	0	0	0	0
Other	0	0	0	0	0
Battery	32	52	52	52	52
Unknown	0	0	0	0	0
Total MW	34,495	35,472	35,623	35,623	35,623

³⁹ NYISO’s 2025 Q3 STAR Report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf>; Explanatory Statement:

https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: <https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf>

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2024 Reliability Needs Assessment*⁴⁰ found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC's resource adequacy criterion of "one day in 10 years." The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFER) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource

adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

ProbA Results

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

⁴⁰ <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>

NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

EUE Heat Maps – 2029

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

Month	Hour																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	7%	24%	25%	7%	3%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.



Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as electric vehicle charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO’s end-use models and are reflected in the baseline, scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year’s forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York’s grid increase in response to the state’s climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

Significant new resource development will be required to achieve New York's energy targets under the CLCPA. According to the [2023–2042 System and Resource Outlook](#) the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO's interconnection process⁴¹ contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

⁴¹ <https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx>

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York's public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFs, will likely be part of this transformation.

On June 23, 2025,⁴² New York's governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is preparing the implementation of a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resource models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

⁴² <https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy>

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison's proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

⁴³ <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>

⁴⁴ https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf

⁴⁵ NYISO's 2025 Q3 STAR Report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf> and Explanatory Statement:

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

NYISO's *2024 Reliability Needs Assessment*⁴³ (RNA) and subsequent analysis⁴⁴ identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO's 2025 Quarter 3 STAR report⁴⁵ identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: <https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf>

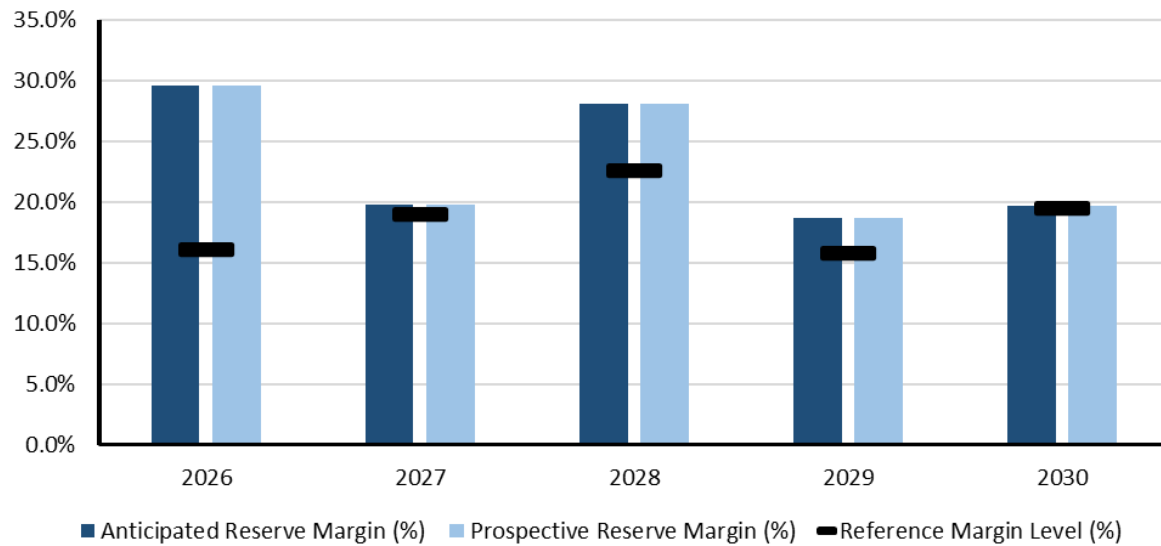


NPCC-Ontario

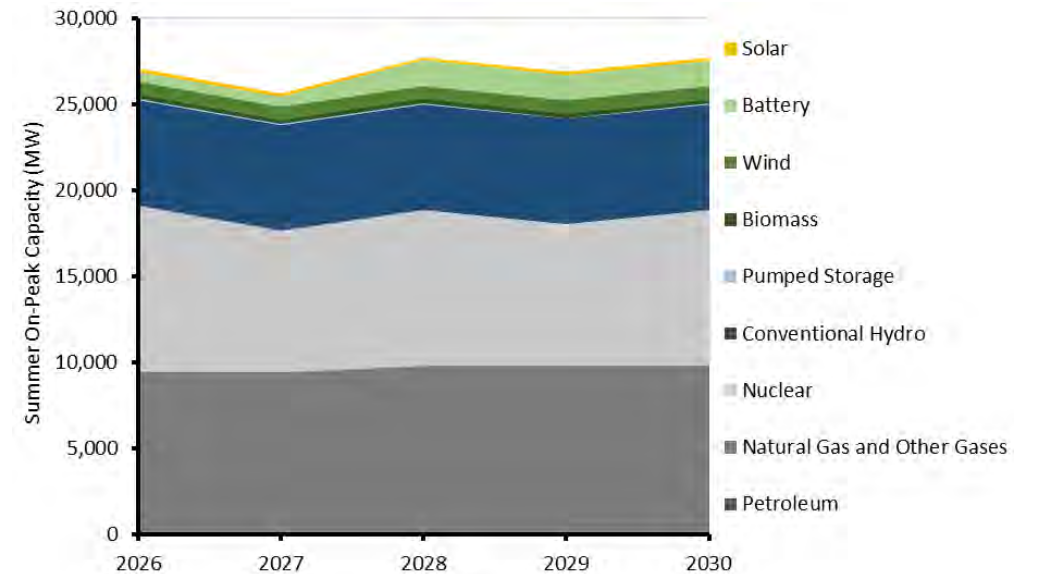
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	23,403	24,023	24,514	25,587	26,443	26,927	27,747	28,621	29,202	29,974
Demand Response	2,046	1,998	2,090	2,092	2,093	2,095	2,096	2,098	2,099	2,101
Net Internal Demand	21,357	22,025	22,424	23,495	24,350	24,832	25,651	26,523	27,103	27,873
Additions: Tier 1	853	853	2,156	2,156	2,156	2,964	3,507	4,051	4,579	5,387
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	600	600	600	1,233	1,324	1,324
Net Firm Capacity Transfers	602	772	1,002	1,002	1,432	1,002	302	302	302	302
Existing-Certain and Net Firm Transfers	26,833	25,541	26,577	25,737	26,999	25,623	25,767	25,767	26,611	26,611
Anticipated Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Prospective Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Reference Margin Level (%)	16.1%	19.0%	22.6%	15.8%	19.5%	13.9%	14.7%	9.6%	14.3%	13.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Ontario Highlights

- Ontario’s ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario’s 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year’s LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO’s reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario’s generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario’s planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	3	3	3	3	3
Natural Gas	9,385	9,385	9,790	9,790	9,790
Biomass	299	304	310	310	310
Solar	150	150	150	150	150
Wind	724	725	728	732	732
Conventional Hydro	6,163	6,163	6,163	6,163	6,163
Pumped Storage	38	38	38	38	38
Nuclear	9,724	8,256	9,059	8,214	9,047
Battery	597	597	1,489	1,489	1,489
Total MW	27,084	25,622	27,731	26,891	27,723

NPCC-Ontario Assessment

Planning Reserve Margins

Ontario's ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year's publication.

The [IESO calculates](#) Ontario's reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 [Annual Planning Outlook \(APO\) includes reserves](#) of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the 2025 LTRA, the IESO applied NERC's definitions for Tier 1 and Tier 3 resources. The IESO's Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It's important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The 2025 LTRA assesses reliability independent of contractual status, unlike the [2025 APO](#), which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the 2025 LTRA outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The [RAF](#) remains unchanged since the 2024 LTRA and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Ontario conducts annual energy adequacy assessments using Energy Exemplar's Plexos software, which models the province's nodal transmission network and simulates dispatch under expected

system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA's purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the [Reliability Outlook \(RO\)](#), which evaluates energy adequacy over an 18-month horizon. These [assessments](#) use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as [capacity auctions](#), coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario's energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.043	0.001	0.066
NEUE (ppm)	0.000	0.000	0.000
LOLH (hours per Year)	0.000	0.000	0.000
*Provides the 2024 ProbA Results for Comparison			

Demand

Ontario's demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the 2024 LTRA were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO's demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts [System Impact Assessments \(SIA\)](#) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

Demand-Side Management

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the 2024 LTRA, the [Peak Perks program](#) has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the [Industrial Conservation Initiative \(ICI\)](#), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a \$1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

Distributed Energy Resources

Ontario's DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the [Enabling Resources Program \(ERP\)](#), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO's [DER Potential Study](#) and Local Generation Program aim to further integrate DERs into Ontario's RAF.

Generation

Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO's [Market Renewal's](#) Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario's long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO's second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario's adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario's generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

Energy Storage

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario's ability to manage variability and meet ramping needs.

Capacity Transfers

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The [2016 agreement](#) allows for a 500 MW swap, while the [2024 agreement](#) enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario's planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario's transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO's internal studies.

Transmission

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a [Transmitter Selection Framework \(TSF\)](#) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

Reliability Issues

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario’s gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO’s Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario’s planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

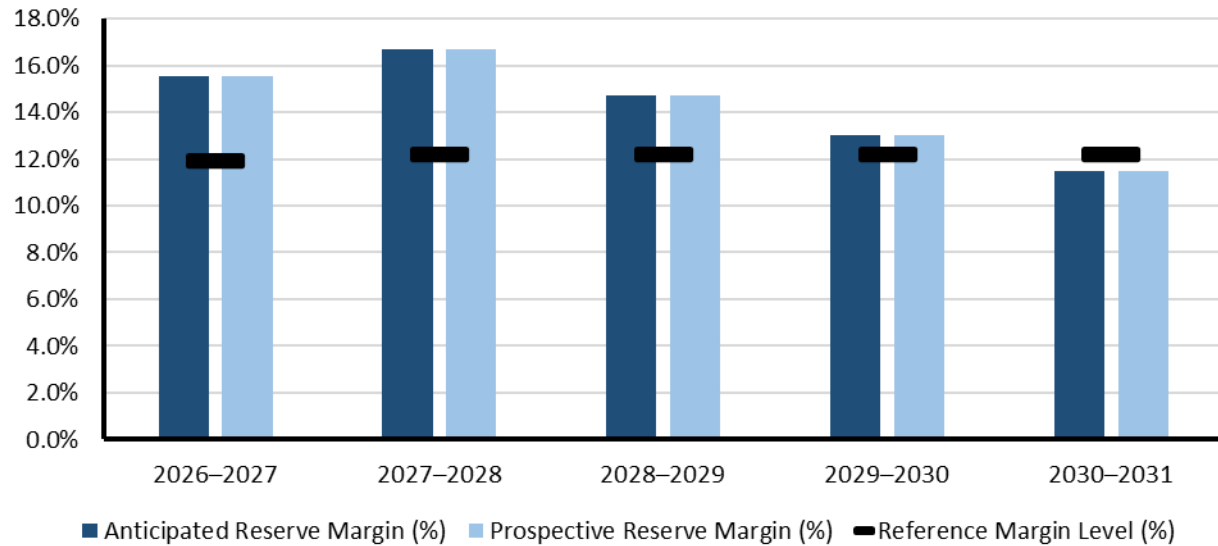


NPCC-Québec

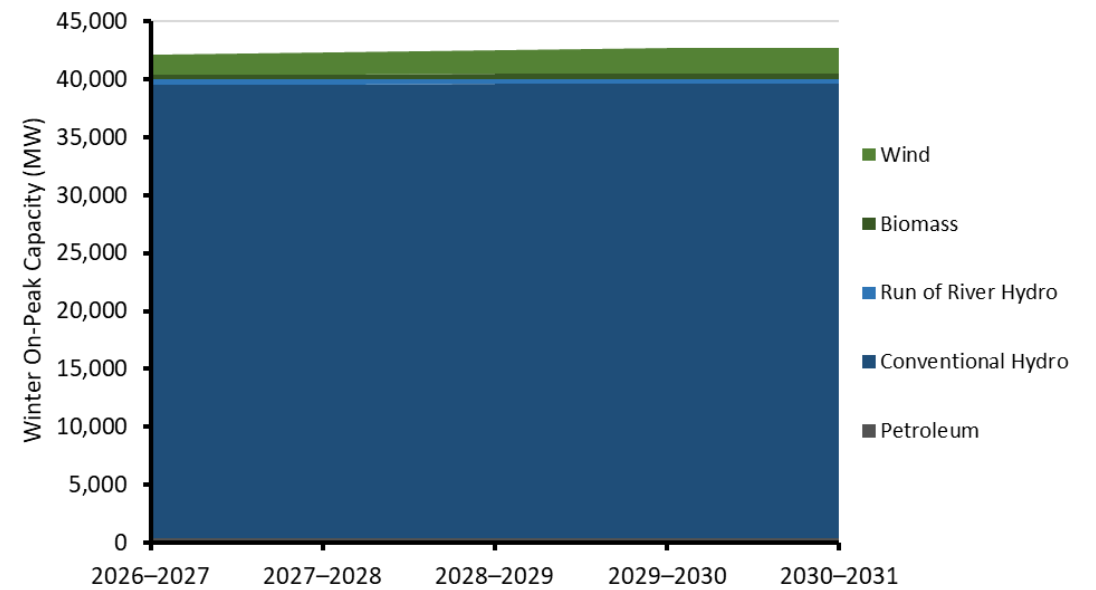
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	41,405	41,901	42,833	43,635	44,392	45,116	46,053	47,148	48,164	49,613
Demand Response	5,058	5,224	5,367	5,445	5,533	5,587	5,618	5,606	5,562	5,562
Net Internal Demand	36,347	36,677	37,465	38,191	38,859	39,529	40,435	41,542	42,602	44,051
Additions: Tier 1	412	566	710	891	891	891	891	891	891	891
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-145	455	455	455	600	0	0	0	0	0
Existing-Certain and Net Firm Transfers	41,591	42,231	42,269	42,272	42,421	41,825	41,830	41,834	41,838	41,842
Anticipated Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Prospective Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Reference Margin Level (%)	11.9%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec’s Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Petroleum	429	429	429	429	429
Biomass	405	405	405	405	405
Wind ⁴⁶	1,778	1,931	2,076	2,257	2,257
Conventional Hydro	39,091	39,129	39,167	39,170	39,175
Run of River Hydro	445	447	447	447	447
Total MW	42,148	42,342	42,524	42,708	42,712

⁴⁶ Expected at-peak capacity.

NPCC-Québec Assessment

Planning Reserve Margins

ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec's installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.⁴⁷

ProbA Summary of Results			
	2026*	2027-2028	2029-2030
EUE (MWh)	8.205	0.01	62.99
NEUE (ppm)	0.040	0.000	0.29
LOLH (hours per Year)	0.014	0.000	0.11
*Provides the 2024 ProbA Results for Comparison			

Demand

Québec's demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data

centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

Demand-Side Management

Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

Distributed Energy Resources

BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec's winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

Generation

4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

Energy Storage

No energy storage resources are currently planned for commissioning during the assessment period.

⁴⁷ 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

Capacity Transfers

Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

Transmission

Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

Reliability Issues

Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec's large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

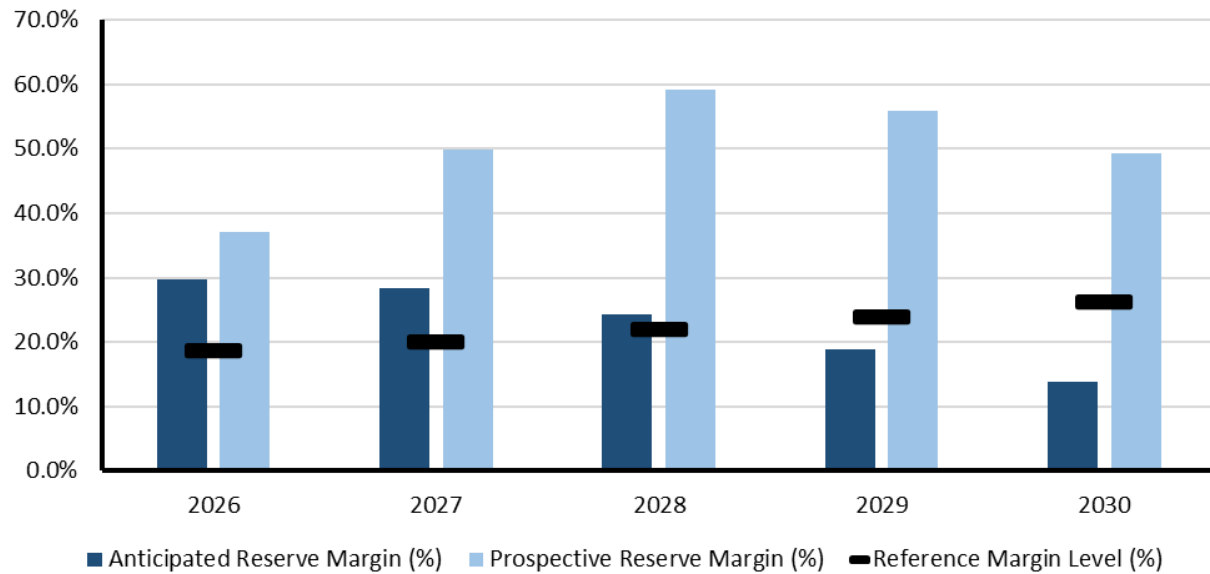


PJM

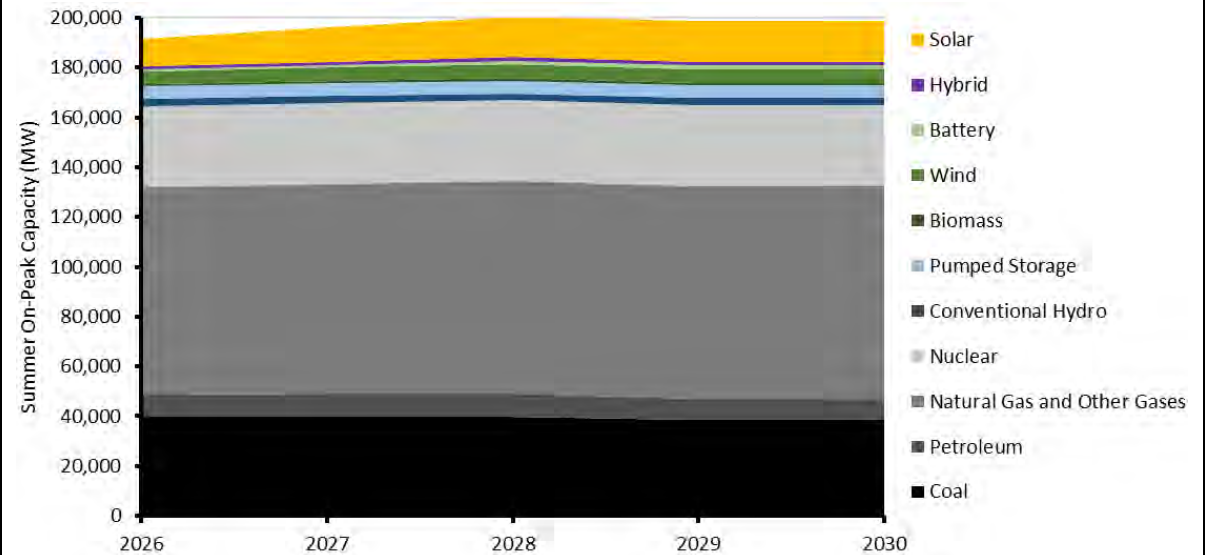
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM’s footprint covers approximately 369,054 square miles and has an approximate population of 67 million people. PJM is the area’s BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	158,937	164,186	169,981	176,094	183,883	192,647	200,507	204,197	207,253	209,923
Demand Response	8,184	8,439	8,703	9,002	9,398	9,845	10,250	10,409	10,533	10,629
Net Internal Demand	150,753	155,747	161,278	167,092	174,485	182,802	190,257	193,788	196,720	199,294
Additions: Tier 1	5,861	10,177	14,521	14,709	14,709	14,709	14,709	14,709	14,709	14,709
Additions: Tier 2	12,410	38,519	65,315	71,119	75,116	75,290	77,655	77,655	77,655	77,655
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	3,840	3,818	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	189,693	189,644	186,005	184,030	184,030	184,030	184,030	184,030	184,030	184,030
Anticipated Reserve Margin (%)	29.7%	28.3%	24.3%	18.9%	13.9%	8.7%	4.5%	2.6%	1.0%	-0.3%
Prospective Reserve Margin (%)	37.0%	49.9%	59.1%	55.9%	49.3%	42.6%	27.7%	25.4%	23.5%	20.0%
Reference Margin Level (%)	18.6%	20.1%	21.9%	23.9%	26.3%	28.9%	30.8%	33.0%	35.1%	35.1%



Planning Reserve Margins



Existing and Tier 1 Resources

PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	39,866	39,866	39,866	38,288	38,288
Coal*	39,866	37,738	27,448	28,002	26,464
Petroleum	8,952	9,163	9,163	8,766	8,766
Natural Gas	83,210	84,150	85,385	85,385	85,385
Natural Gas*	82,589	83,443	84,678	84,678	84,678
Biomass	857	907	907	907	907
Solar	11,282	13,616	16,141	16,328	16,328
Wind	5,251	5,496	5,622	5,622	5,622
Conventional Hydro	2,807	2,829	2,829	2,829	2,829
Pumped Storage	5,068	5,068	5,068	5,068	5,068
Nuclear	32,508	32,508	32,508	32,508	32,508
Hybrid	1,187	1,504	1,504	1,504	1,504
Battery	703	895	1,531	1,531	1,531
Total MW	191,712	196,002	200,524	198,737	198,737
Total MW*	191,091	193,166	187,399	187,743	186,205

*Capacity with additional generator retirements. Generators that are forecasted to retire by PJM are removed from the resource projection where marked.

PJM Assessment

Planning Reserve Margins

The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.⁴⁸

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

Probabilistic Assessments (NERC ProbA and Other Studies)

LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	538	3,251	67,580
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.11	0.61	9.97
* Provides the 2024 ProbA Results for Comparison			

Demand

The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

⁴⁸ <https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf>

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM's projected load indicators in many instances have doubled from the 2024 LTRA projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year's projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

Demand-Side Management

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM's probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

Distributed Energy Resources

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

Generation

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original 2025 LTRA data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original 2025 LTRA data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM's Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if its transfers were dropped to zero.

Transmission

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved \$5.9 billion worth of regional and local projects to address the reliability criteria violations.

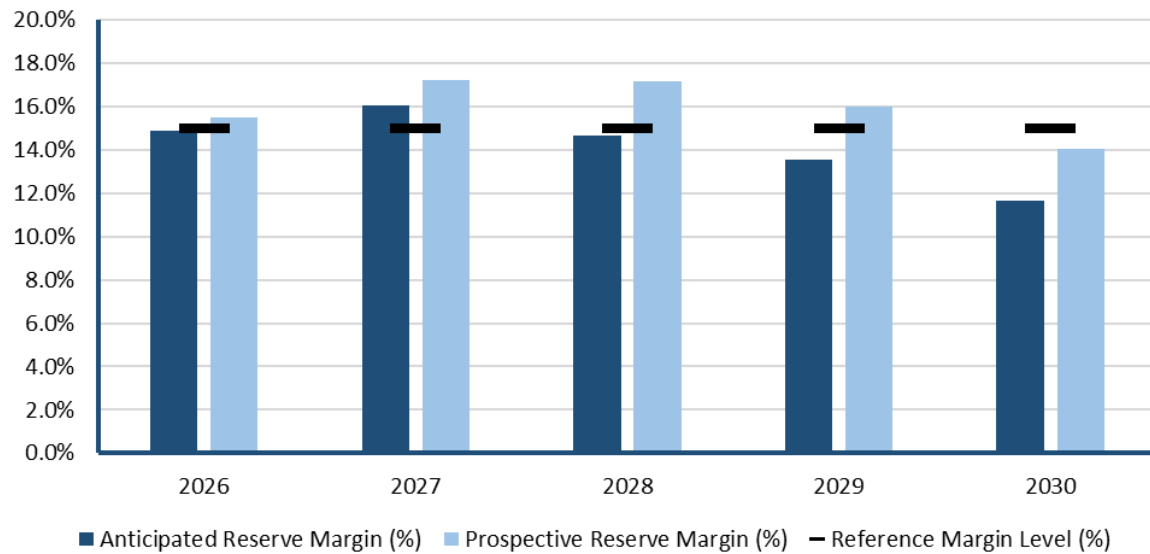


SERC-Central

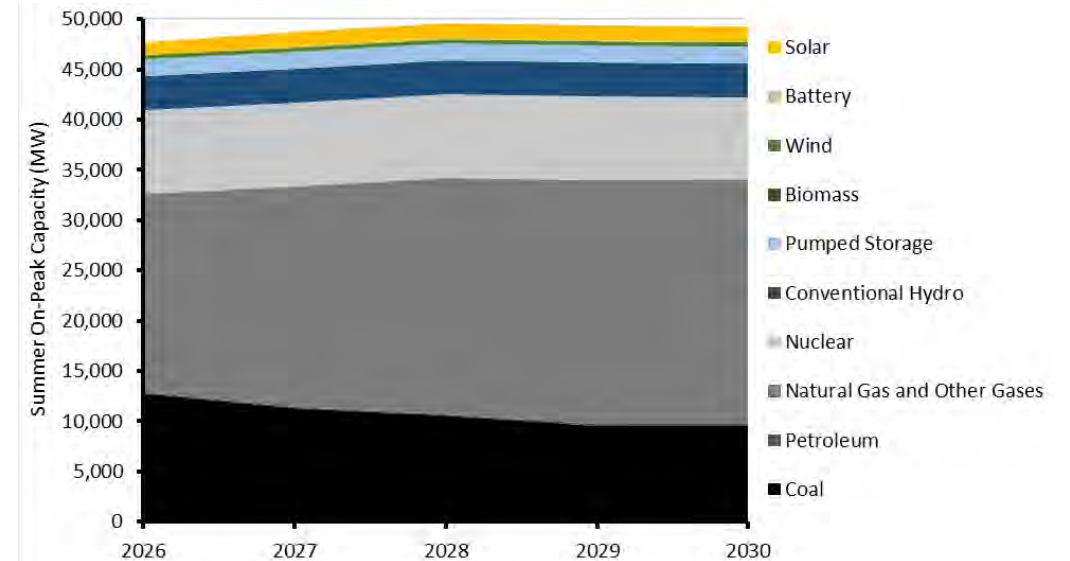
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	43,066	43,512	44,298	44,616	45,280	45,975	46,034	46,168	46,412	46,619
Demand Response	2,818	3,047	3,287	3,356	3,364	3,377	3,392	3,367	3,323	3,301
Net Internal Demand	40,248	40,465	41,011	41,260	41,916	42,598	42,642	42,801	43,089	43,317
Additions: Tier 1	518	492	4,567	5,435	5,435	5,435	5,435	5,435	5,435	5,735
Additions: Tier 2	20	245	837	837	837	837	837	837	837	837
Additions: Tier 3	178	234	300	362	743	795	2,107	3,293	5,539	5,591
Net Firm Capacity Transfers	460	391	-288	-287	-287	-221	-221	-220	-220	-157
Existing-Certain and Net Firm Transfers	47,859	47,438	45,895	44,503	43,474	43,382	43,448	42,484	42,485	41,414
Anticipated Reserve Margin (%)	19.1%	20.8%	19.7%	18.5%	16.5%	14.8%	12.4%	12.0%	8.7%	9.0%
Prospective Reserve Margin (%)	19.7%	22.0%	22.3%	21.1%	19.0%	17.3%	14.9%	14.5%	11.2%	11.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	12,782	11,308	10,595	9,565	9,565
Coal*	12,782	11,308	9,944	8,914	8,914
Petroleum	128	128	128	128	128
Natural Gas	19,706	21,956	23,483	24,341	24,249
Natural Gas*	19,279	21,529	22,585	23,443	23,443
Biomass	37	37	37	37	37
Solar	1,181	1,408	1,445	1,455	1,455
Wind	370	370	370	370	370
Conventional Hydro	3,405	3,405	3,405	3,405	3,405
Pumped Storage	1,247	1,247	1,247	1,247	1,247
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	100	135	135	135	135
Total MW	47,236	48,274	49,124	48,963	48,871
Total MW*	47,256	48,267	47,996	47,835	47,835

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

SERC-Central Assessment

Planning Reserve Margins

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the 2024 LTRA, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities' ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

ProbA Results

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.10	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

Demand

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are

refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

Demand-Side Management

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

Distributed Energy Resources

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity's Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

Generation

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the 2024 LTRA, with entities projecting no new retirements.

Changing Resource Mix and Operational Considerations: Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a "burn-in" period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for

automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

Addressing Net Demand Ramping Needs: Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

Capacity Contribution Values for Various Resources: Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

IBR Performance and Reliability: Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

Generator Retirements

Natural Gas Fuel Supply Risk: Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

Energy Storage

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

Capacity Transfers

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.

- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
 - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
 - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
 - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

Transmission

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
 - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
 - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
 - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
 - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability
- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
 - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
 - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
 - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
 - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
 - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
 - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
 - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

Reliability Issues

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

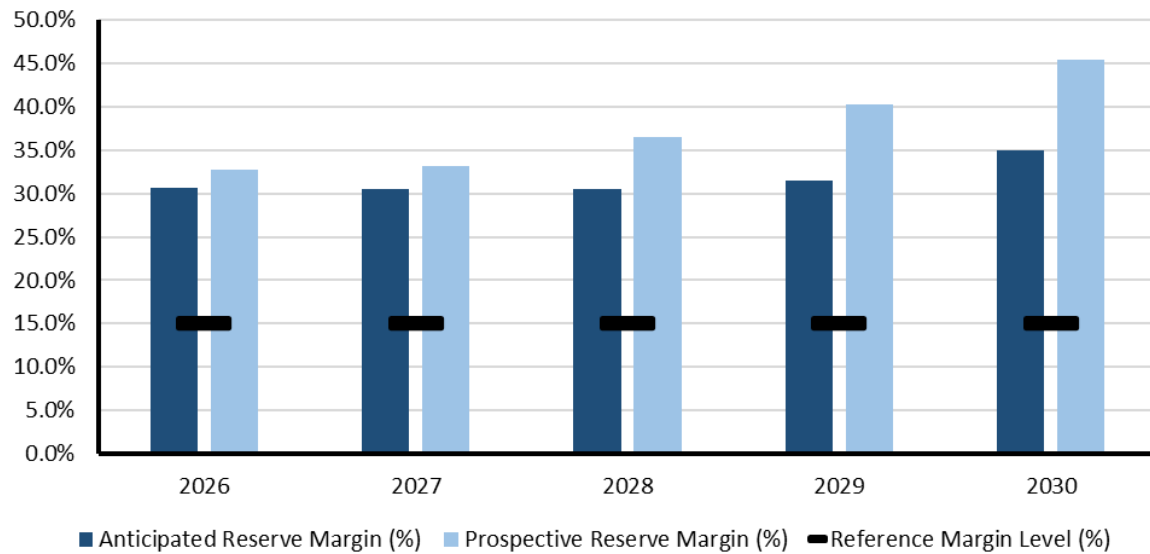


SERC-East

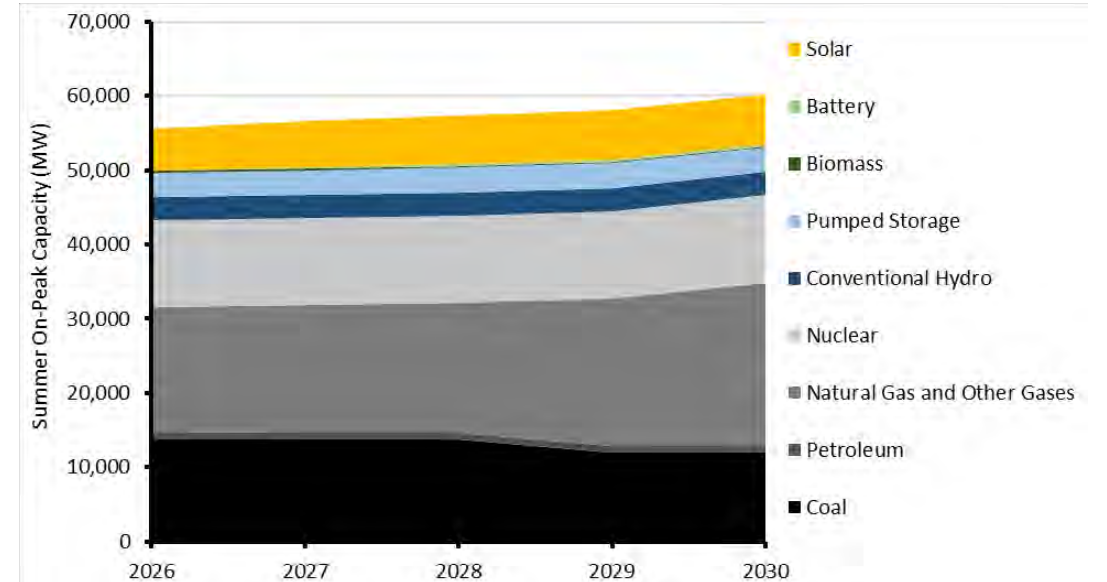
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	44,414	45,289	45,893	46,128	46,646	47,256	47,776	48,445	48,870	49,313
Demand Response	1,608	1,620	1,621	1,652	1,679	1,702	1,726	1,751	1,773	1,795
Net Internal Demand	42,806	43,669	44,272	44,476	44,967	45,554	46,050	46,694	47,097	47,518
Additions: Tier 1	959	2,109	2,817	5,282	7,348	8,656	9,921	11,186	11,186	11,186
Additions: Tier 2	215	484	2,009	3,231	4,045	4,551	5,114	6,232	9,022	9,022
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	150	150	150	236	236	236	236	236	236	236
Existing-Certain and Net Firm Transfers	54,964	54,880	54,953	53,222	53,316	52,237	50,919	50,919	49,557	49,557
Anticipated Reserve Margin (%)	30.6%	30.5%	30.5%	31.5%	34.9%	33.7%	32.1%	33.0%	29.0%	27.8%
Prospective Reserve Margin (%)	32.7%	33.1%	36.5%	40.3%	45.4%	45.1%	44.7%	47.8%	49.5%	48.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	13,715	13,715	13,715	11,898	11,898
Petroleum	1,044	992	992	992	992
Petroleum*	1,044	868	868	868	868
Natural Gas	16,737	17,081	17,396	19,816	21,851
Biomass	176	176	176	176	176
Solar	5,649	6,223	6,626	6,671	6,702
Conventional Hydro	3,094	3,094	3,094	3,094	3,094
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,808	11,808	11,902
Battery	8	208	258	258	258
Total MW	55,540	56,606	57,388	58,035	60,196
Total MW*	55,540	56,482	57,264	57,911	60,072

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

SERC-East Assessment

Planning Reserve Margins

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the *2024 LTRA*, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an “all-of-the-above” strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar,

batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

Energy Risk, Probabilistic-Based Assessments

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

- **LOLE Studies:** These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- **ELCC Studies:** These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- **Statistical Modeling:** Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- **Stochastic Analysis in Load Forecasting:** To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- **Load Forecast Uncertainty (LFU) Scenarios:** Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

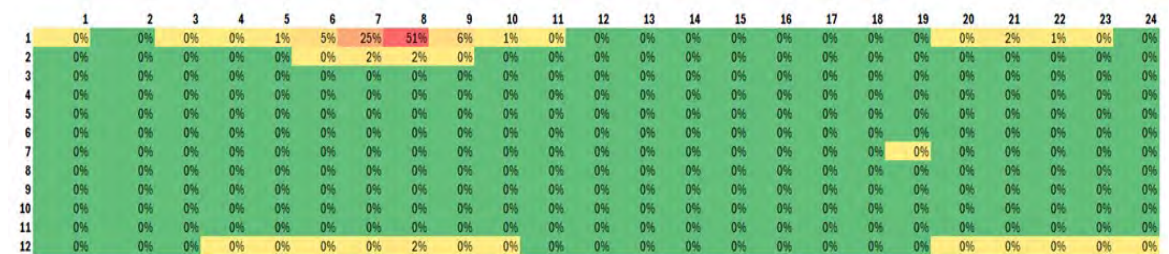
Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time

frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

ProbA Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	231	538
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.16	0.33
*Provides the 2024 ProbA Results for Comparison			

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.



2027 EUE Heat Map

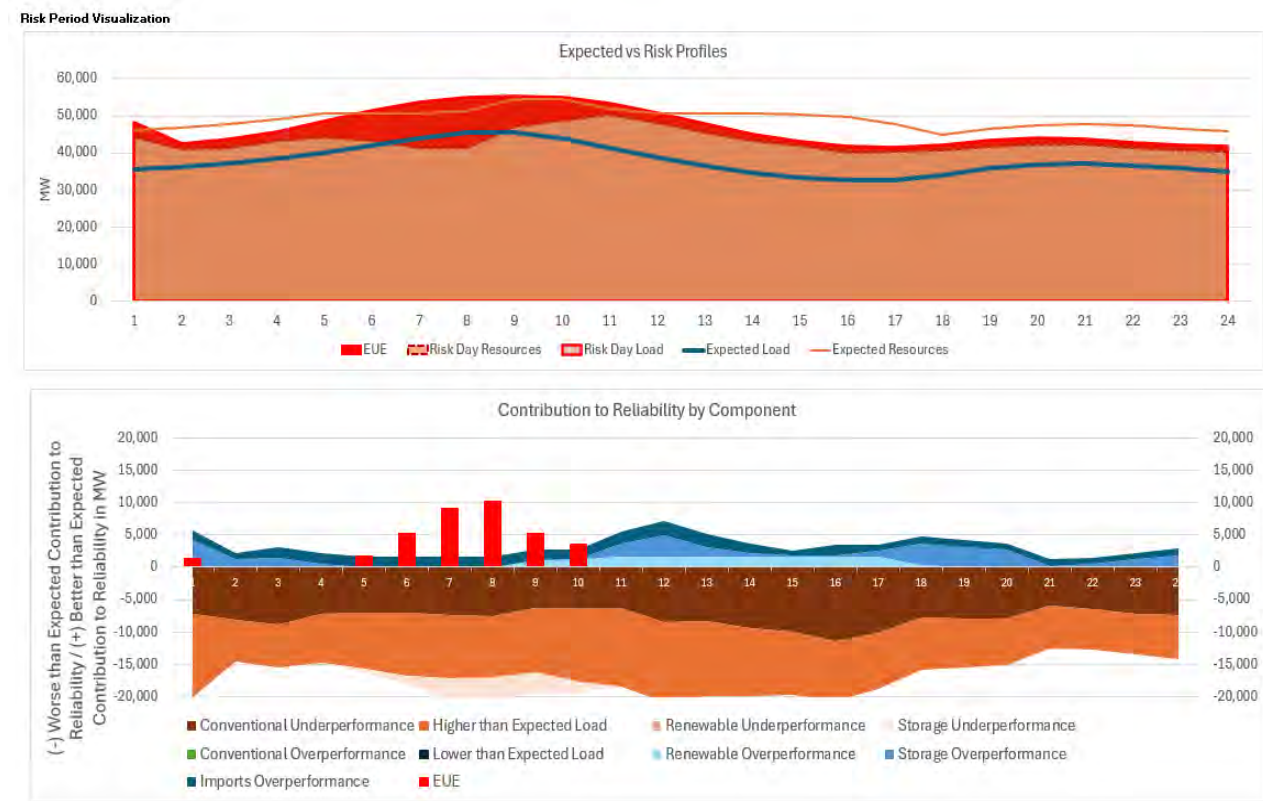
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, there is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProBA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.

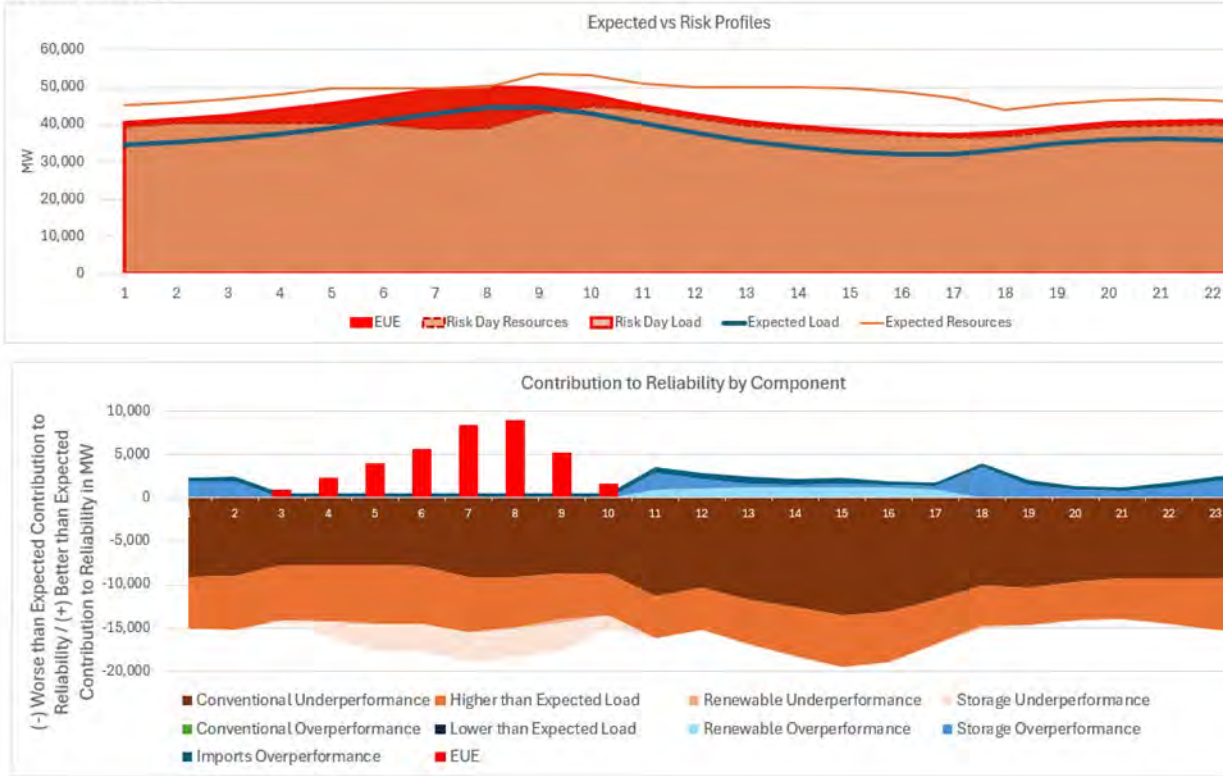


Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).

Risk Period Visualization



Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach

for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through “High” and “Low” scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the 2024 LTRA are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity’s capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a “Bring Your Own Thermostat” initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the 2024 LTRA, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a “Bring Your Own kW” winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the *2024 LTRA*, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the *2024 LTRA*, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability

For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations

Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage

Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential

constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the 2024 LTRA, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

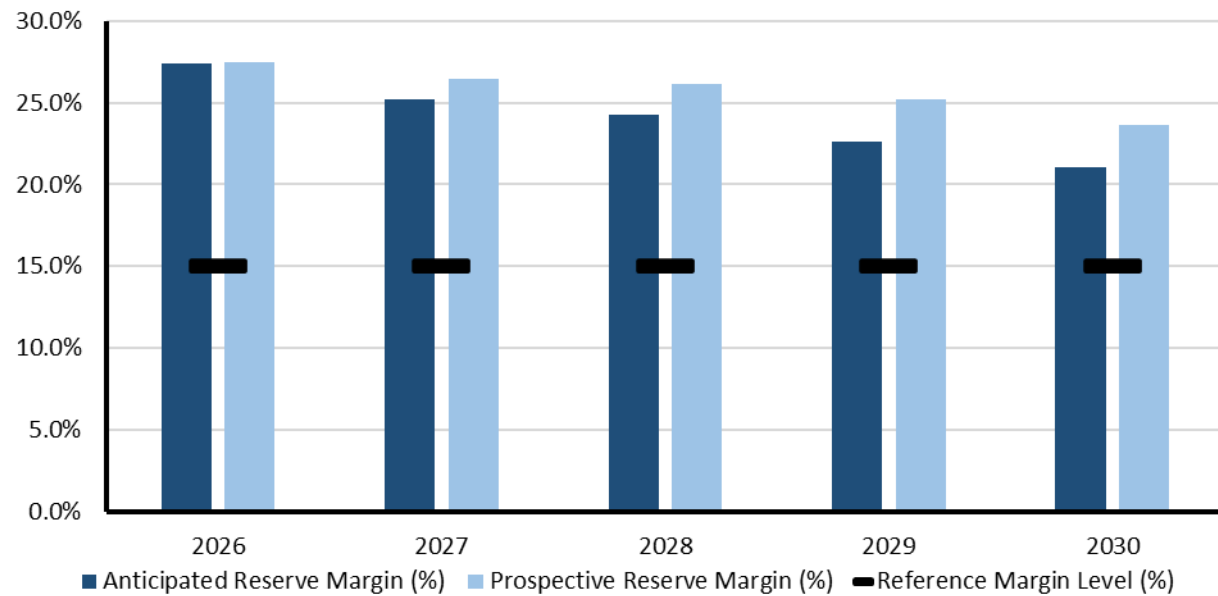


SERC-Florida Peninsula

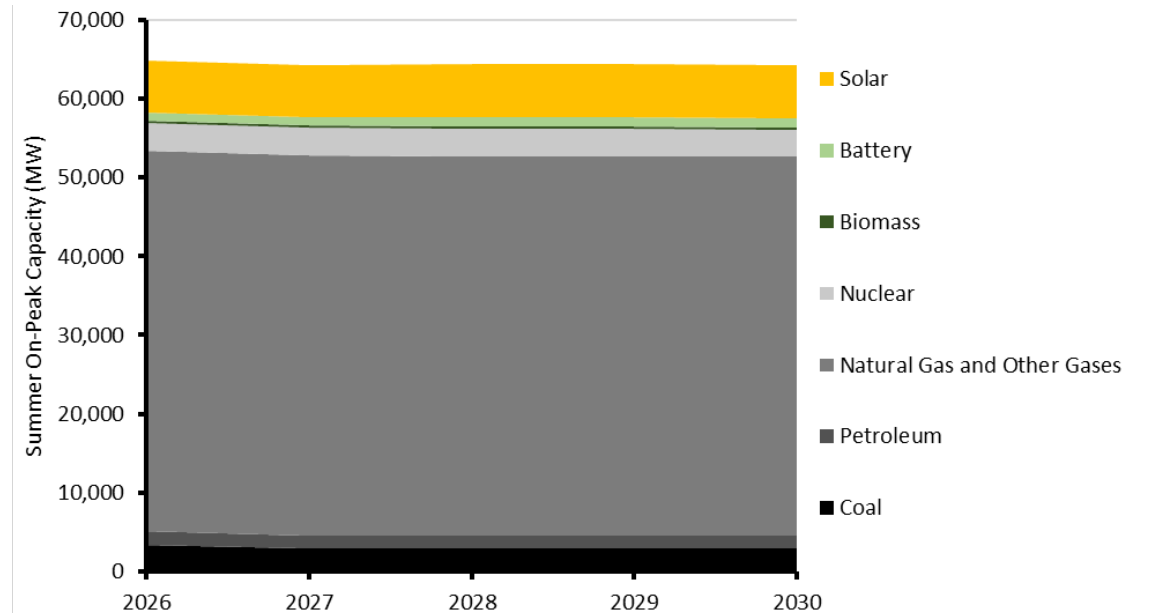
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula’s ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	64,806	63,604	63,757	63,760	63,628

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

SERC-Florida Peninsula Assessment

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida's Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the 2024 LTRA, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC's ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé's SERVVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

ProbA Results

Based on the data and assumptions of SERC’s ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00

* Provides the 2024 ProbA Results for Comparison

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

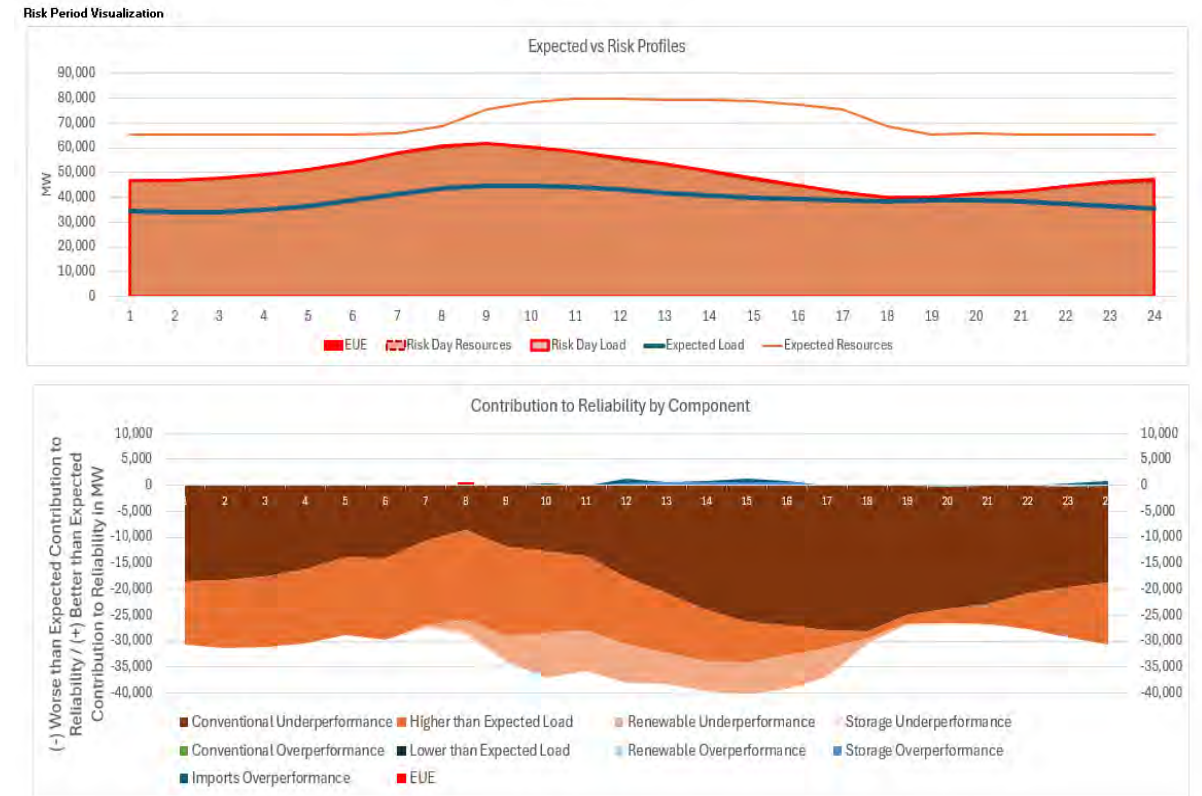
2027 EUE Heat Map

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion's approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently

develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC's Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members' integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
 - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
 - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
 - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
 - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
 - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
 - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk

- The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
- The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
- Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
- Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
- In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
- Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year's reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are “not considered significant in the near-term” for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a “key area of focus.”

- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note “no expected hours of shortfall,” scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area’s “dependency on natural gas as a fuel resource” is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

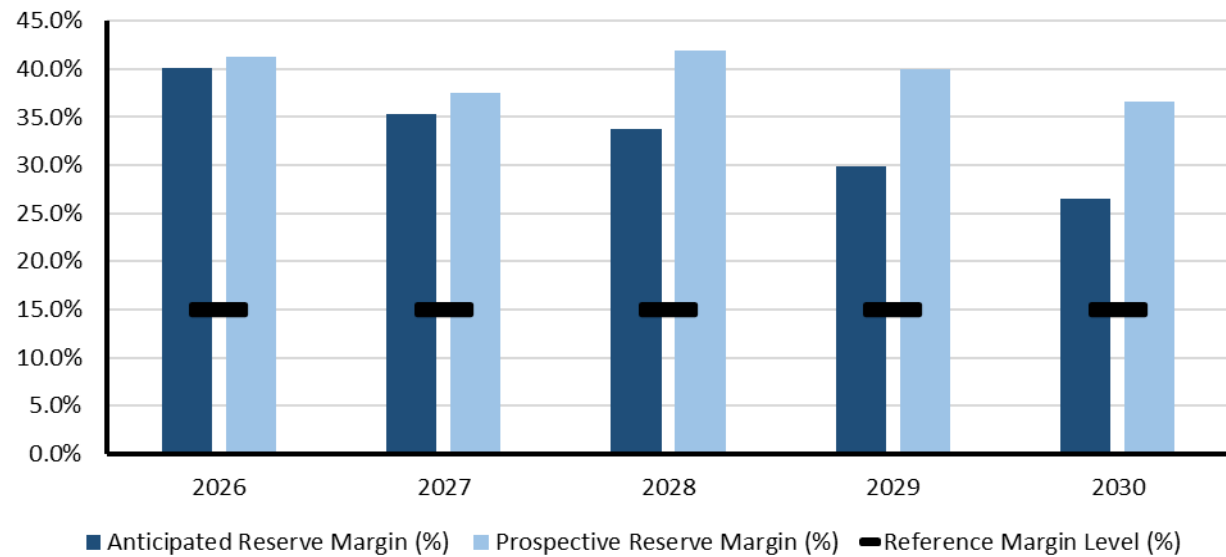


SERC-Southeast

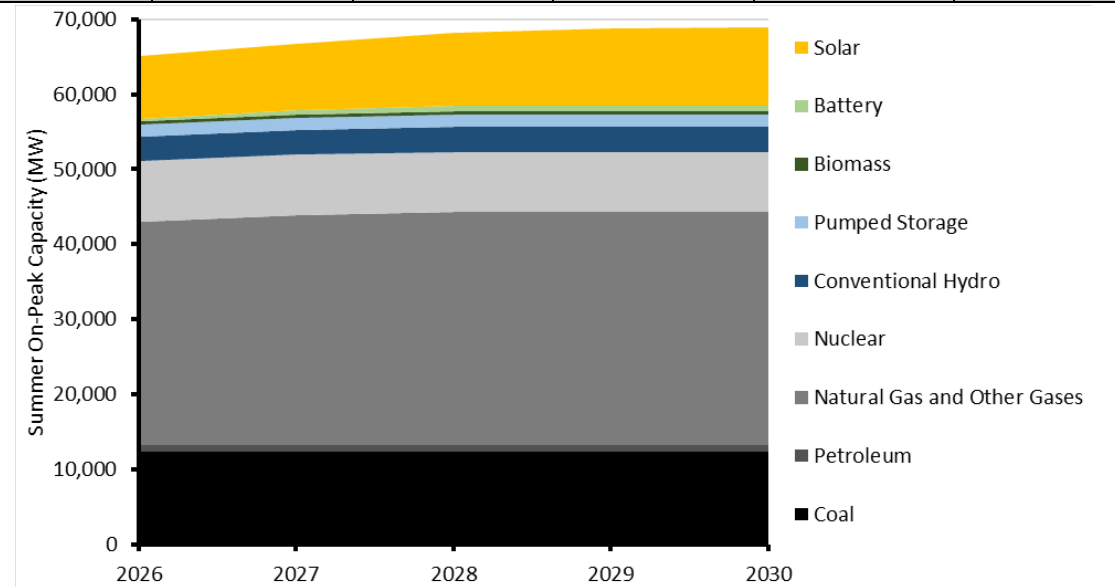
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Southeast Highlights

- SERC-Southeast’s ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632

***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

SERC-Southeast Assessment

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to

serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001

* Provides the 2024 ProbA Results for Comparison

The figure below shows the EUE as a Heat Map for the year 2027.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2027 EUE Heat Map

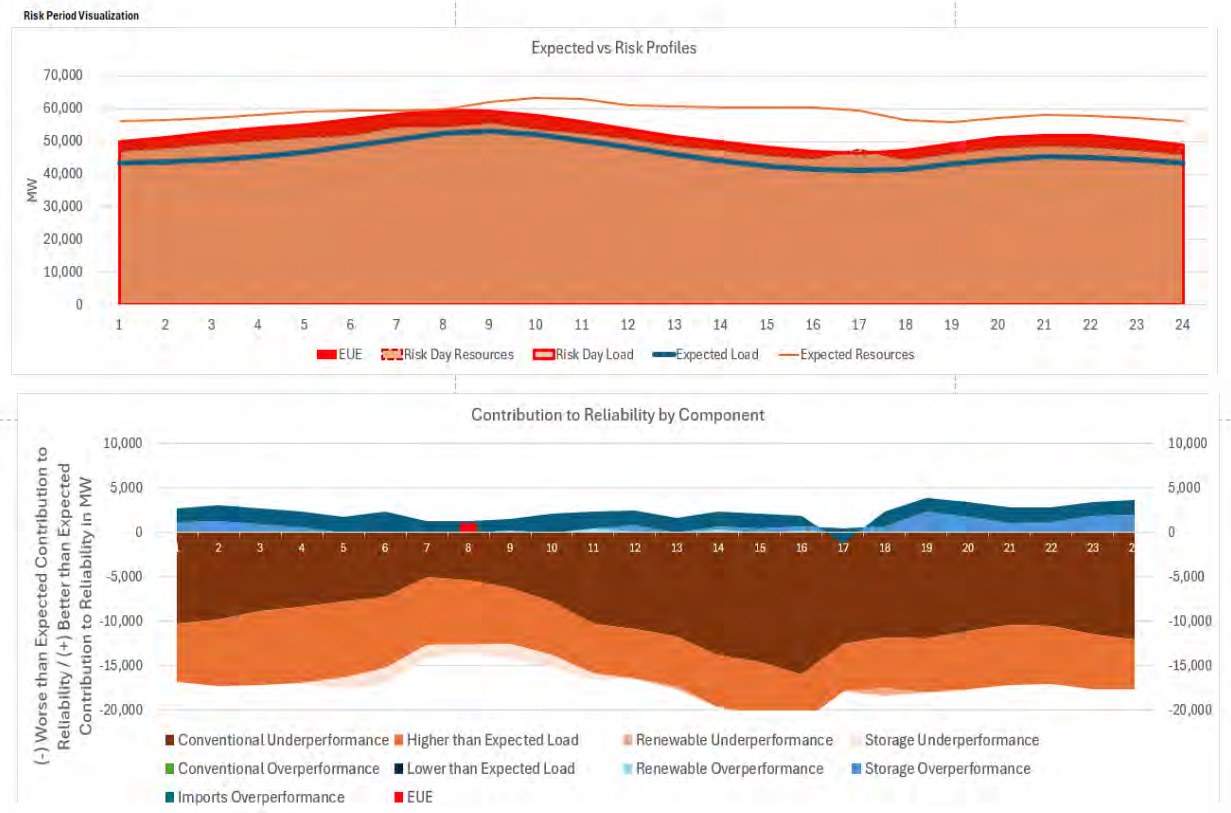
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%

2029 EUE Heat Map

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below

show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.



The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

Demand

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

Demand-Side Management

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the 2024 LTRA, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

Distributed Energy Resources

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

Generation

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area’s winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process

coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

Energy Storage

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

Capacity Transfers

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS's ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during

extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

Transmission

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

Reliability Issues

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads:** Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This

increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.

- **Natural Gas Fuel Supply Vulnerability:** Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions:** The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

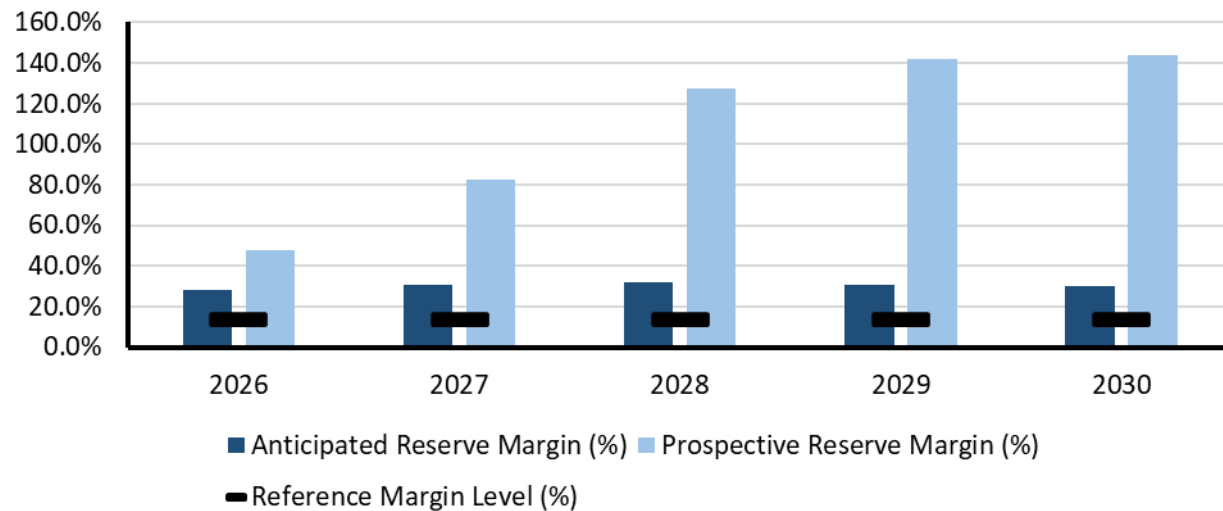


Texas RE-ERCOT

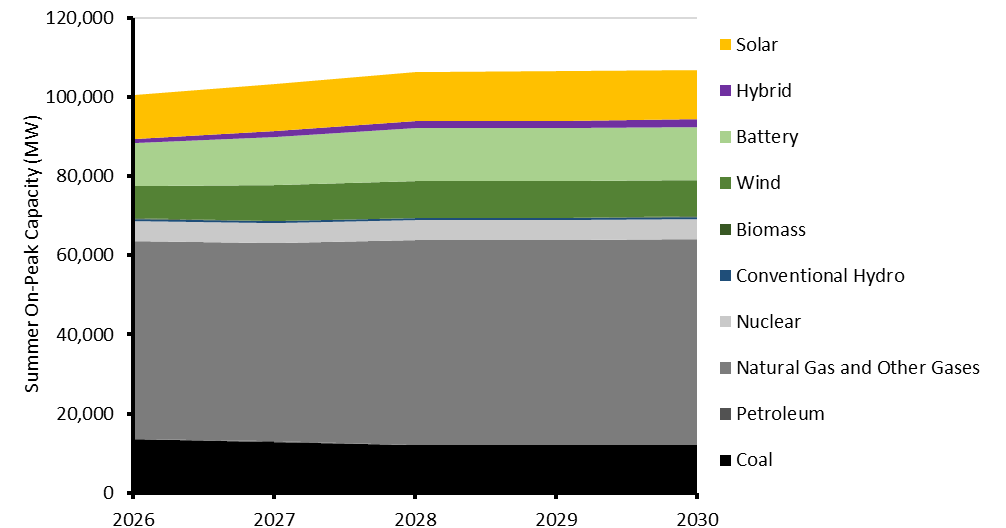
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	94,650	104,295	121,543	128,851	138,944	144,522	148,567	149,846	152,230	154,077
Demand Response	13,346	22,127	37,672	43,888	53,131	57,720	60,942	61,846	62,644	63,321
Net Internal Demand	81,304	82,168	83,871	84,963	85,813	86,802	87,625	88,000	89,586	90,756
Additions: Tier 1	10,377	15,216	18,527	19,037	19,037	19,037	19,037	19,037	19,037	19,037
Additions: Tier 2	15,391	42,413	79,923	95,374	98,707	99,018	99,018	99,018	99,018	99,018
Additions: Tier 3	5,022	17,546	36,405	51,080	58,217	58,217	58,463	58,463	58,463	58,463
Net Firm Capacity Transfers	508	659	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Existing-Certain and Net Firm Transfers	93,870	92,008	92,046	92,113	92,401	92,401	92,401	92,401	92,401	92,401
Anticipated Reserve Margin (%)	28.2%	30.5%	31.8%	30.8%	29.9%	28.4%	27.2%	26.6%	24.4%	22.8%
Prospective Reserve Margin (%)	47.9%	82.3%	127.3%	142.1%	143.9%	141.5%	139.2%	138.2%	134.0%	131.0%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
 - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	13,596	12,941	12,156	12,156	12,156
Coal*	13,596	12,550	11,205	11,205	11,205
Petroleum	30	30	30	30	30
Natural Gas	50,032	50,122	51,689	51,689	51,977
Natural Gas*	50,032	49,764	51,331	51,331	51,619
Biomass	131	131	131	131	131
Solar	11,049	11,923	12,305	12,534	12,534
Wind	8,303	8,900	9,215	9,219	9,219
Conventional Hydro	570	570	570	570	570
Nuclear	4,973	4,973	4,973	4,973	4,973
Hybrid	1,127	1,497	1,813	1,909	1,909
Battery	10,734	12,285	13,375	13,374	13,374
Total MW	100,545	103,372	106,257	106,584	106,872
Total MW*	100,545	102,203	104,528	104,855	105,143

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.
 **Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.

Texas RE-ERCOT Assessment

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year’s LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
* Provides the 2024 ProbA Results for Comparison			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	4%	3%	2%	2%	3%	5%	8%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	5%	4%	
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	2%	2%	2%	2%	2%	3%	4%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%	

2029

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	3%	2%	2%	2%	3%	4%	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	4%	3%	
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	1%	1%	1%	1%	2%	2%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	2%	2%

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	End of Year 2 (2027)	End of Year 5 (2030)	End of Year 10 (2035)
Data Centers	6,700	23,000	25,000
Cryptocurrency Mining Facilities	4,500	7,500	8,500
Hydrogen Electrolysis	3,000	7,902	9,100
Industrial Manufacturing Load	2,800	7,100	7,600

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT’s load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT’s authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the “Controllable and Dispatchable Demand Response” line items.

Summer	Total LL (MW)	LL Curtailment (MW)	Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9	2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5	2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5	2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5	2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6	2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5	2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3	2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9	2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6	2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4	2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6	2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called “Unregistered Distributed Generators” (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year “Reliability Must Run” (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single “integrated” generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT’s “Real Time Co-Optimization + Battery” project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy

storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT’s 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP’s 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT's Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

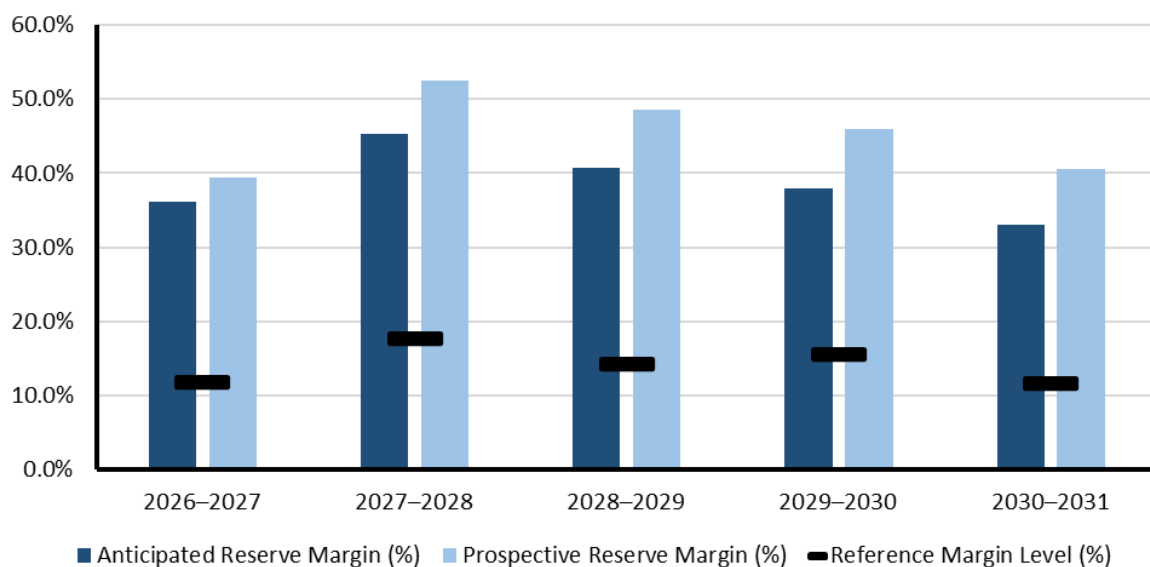


WECC-Alberta

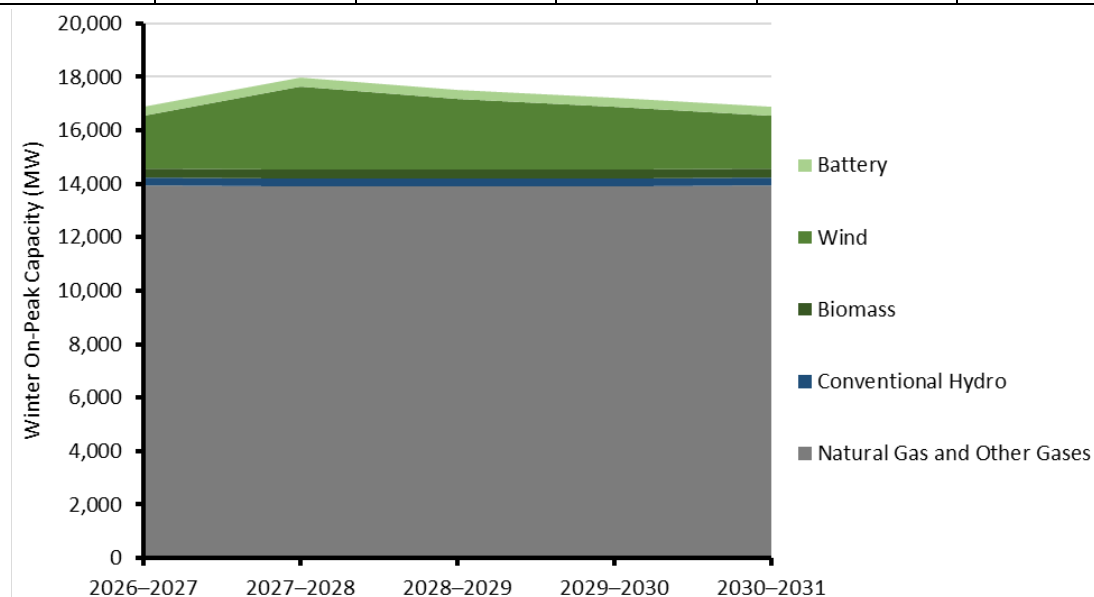
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province’s Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta’s transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta’s ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta’s total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta’s thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta’s 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins

WECC-Alberta's ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk

AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

Demand

Alberta's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management

AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation

Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- **Aging Thermal Resource Fleet:** There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO's ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- **Solar and Wind Variability:** Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- **Electric-Gas Coordination:** As a part of WECC's load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO's system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- **Resource Portfolio, Clean Electricity, and Development Policies:** The Canadian province of Alberta is required to ensure its electricity supply is [30% renewable by 2030](#). Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to the NERC's [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

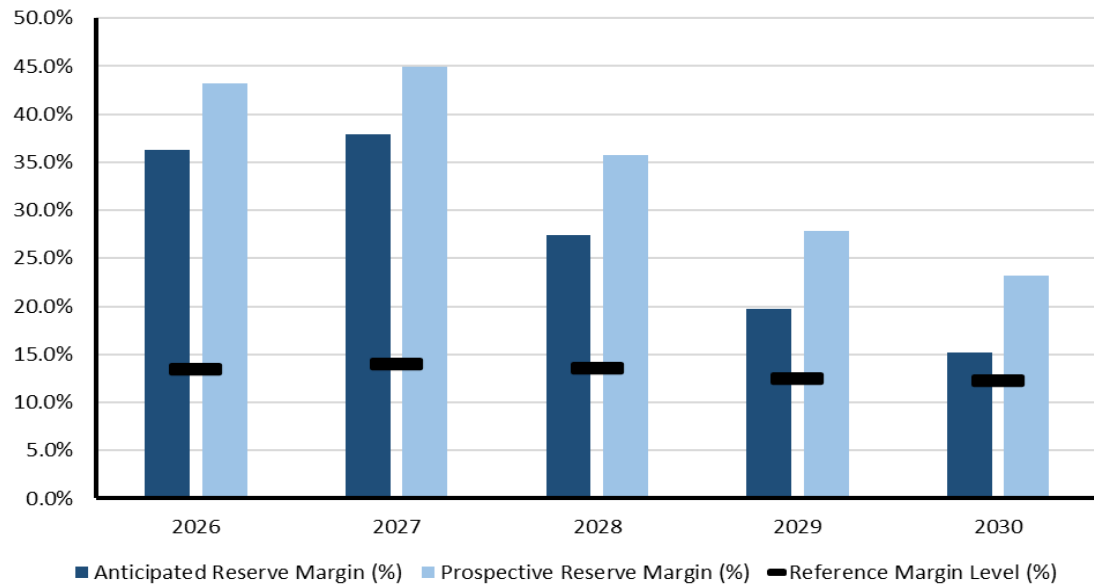


WECC-Basin

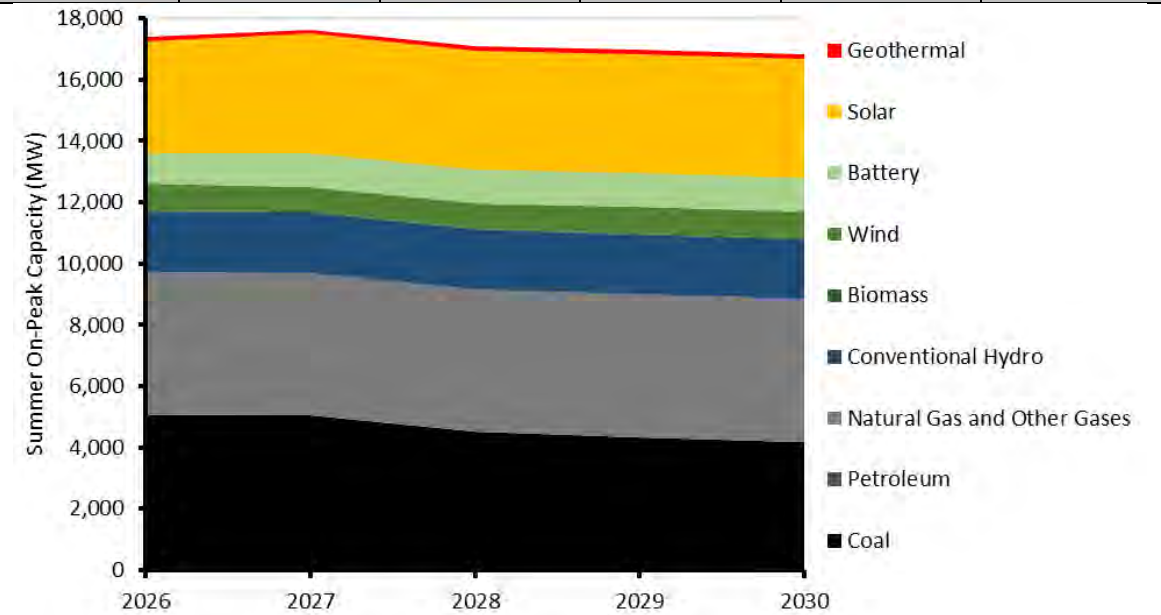
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	17,428	17,672	17,130	17,003	16,839

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

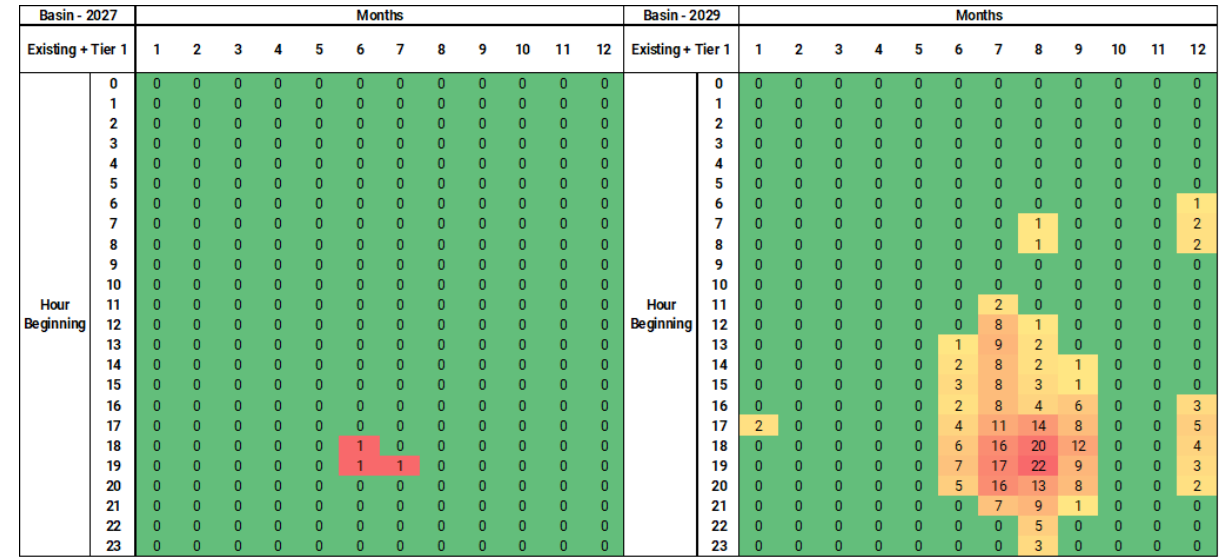
Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC’s internally developed modeling tool that performs energy based ProbAs that support NERC’s LTRA and seasonal assessments, as well as WECC’s Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area’s ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

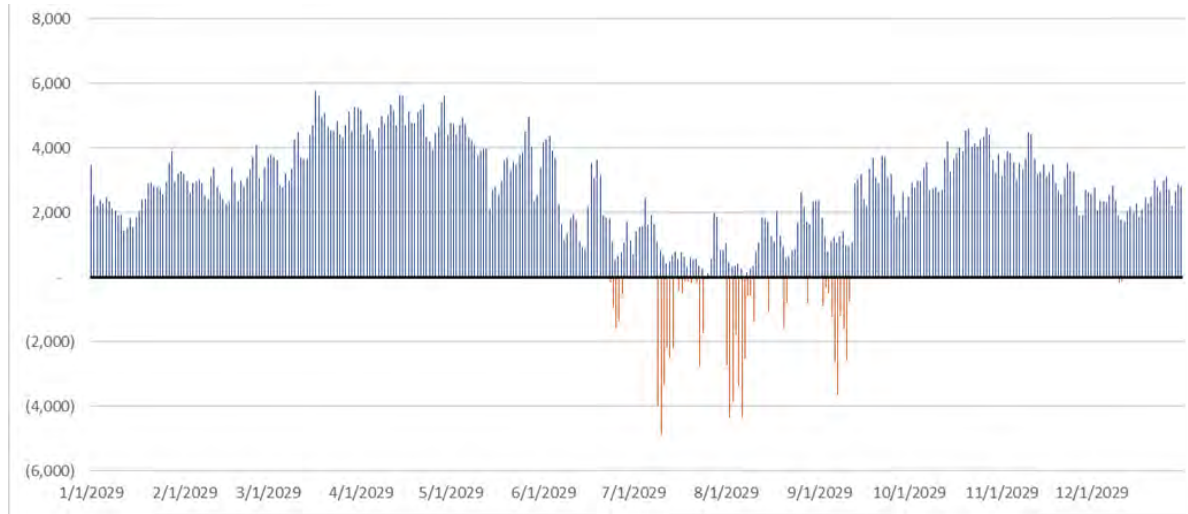
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
* No prior results as the assessment area is new for the 2025 LTRA.			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.



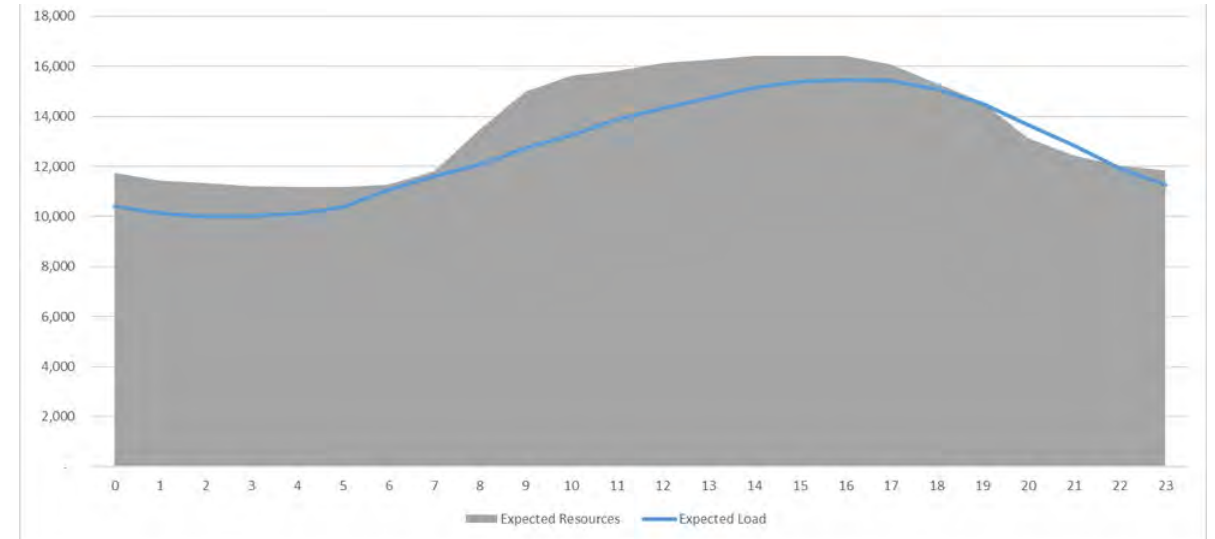
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin’s resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company’s dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting [100% clean electricity by 2045](#); Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's [Energy Gateway Transmission Plan](#) addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

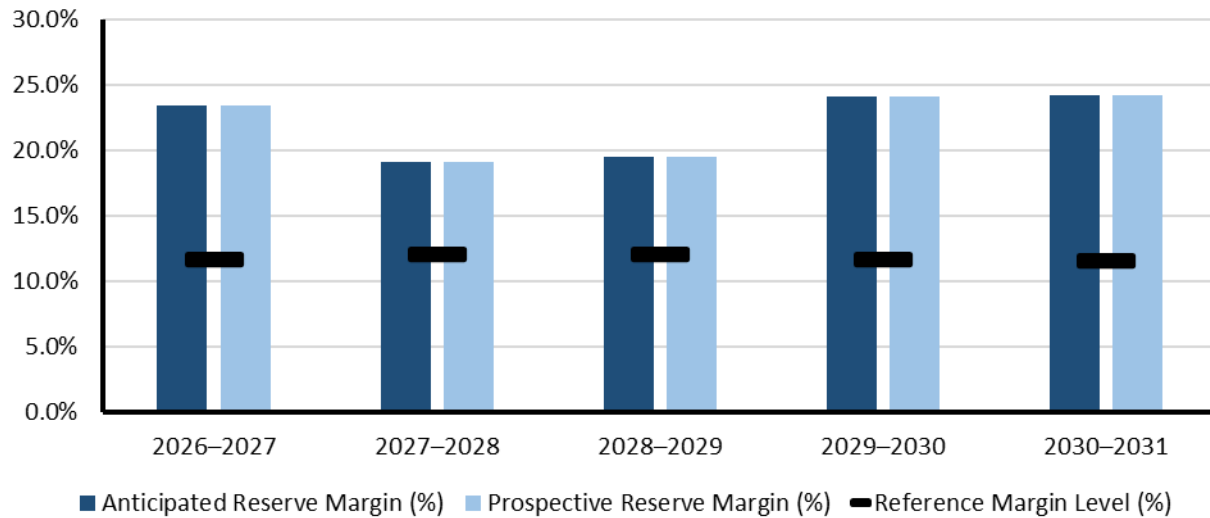


WECC-British Columbia

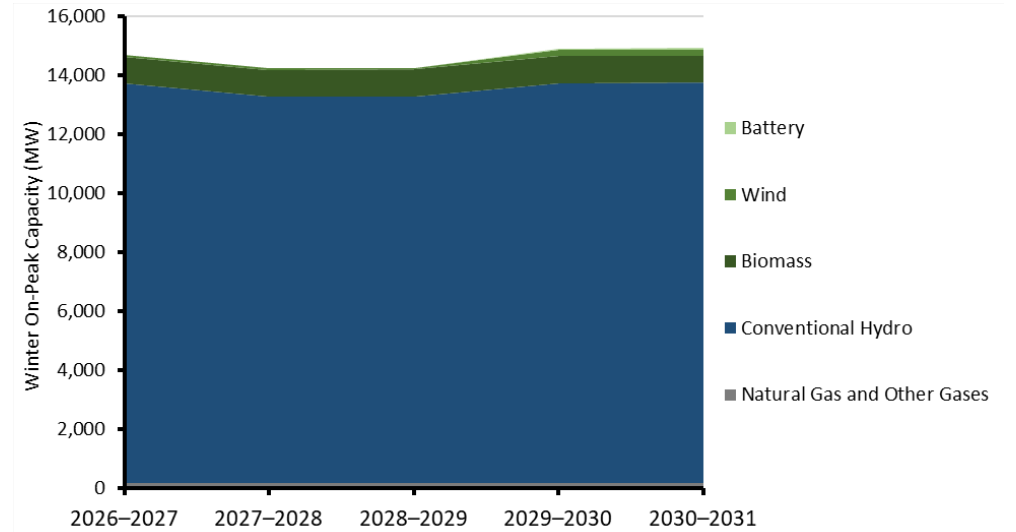
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro’s transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

- WECC-British Columbia’s anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro’s most recent 10-year capital plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia’s ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For [2025–2026 Winter](#), monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For [2026 Summer](#), a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The [CleanBC Roadmap](#) states, “By 2030, BC will phase out BC Hydro’s last gas-powered facility so the electricity we make is 100% clean.”

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia’s capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province’s basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year’s snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC's [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro's most recent 10-Year Capital Plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

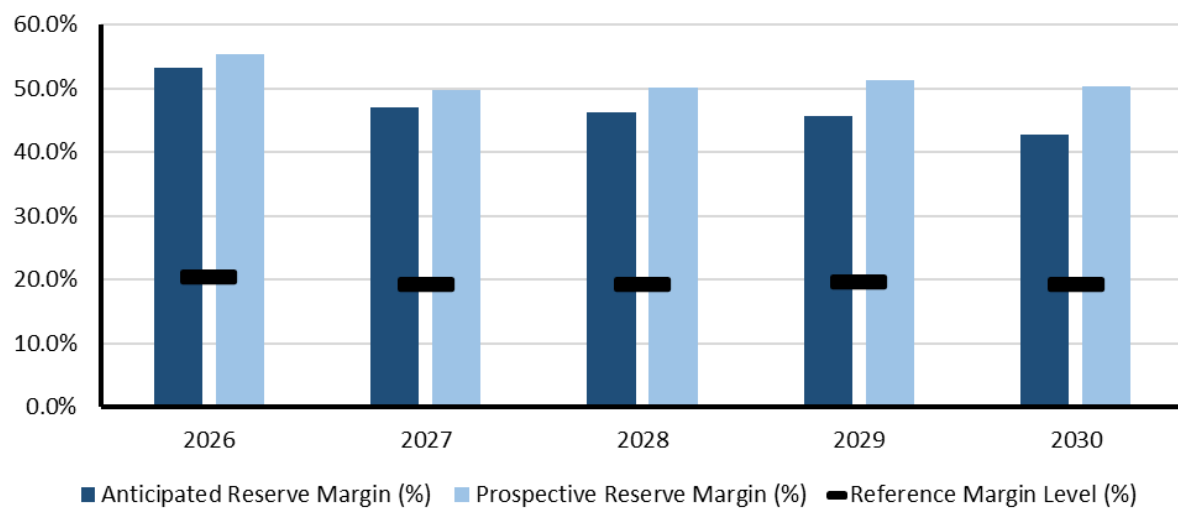


WECC-California

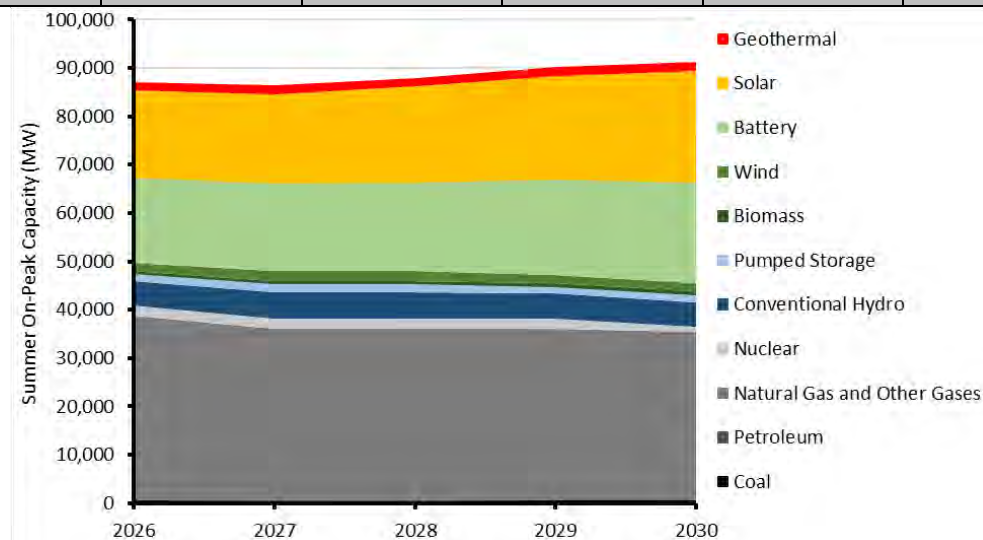
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. [CPUC's ruling](#) also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922

***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-California Assessment

Planning Reserve Margins

The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC’s reserve margins are not used in WECC’s methodology for the LTRA.

Energy Assessment, including non-peak hour risk

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand

Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management

DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources

A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the “net billing tariff” that pays approximately 75% lower rates for energy sent back to the grid. Given California’s shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

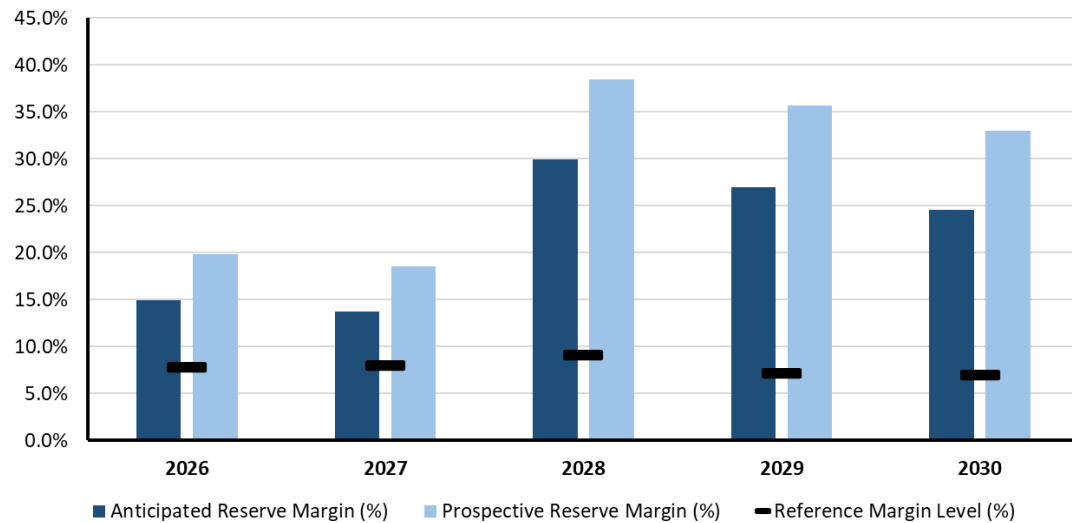


WECC-Mexico

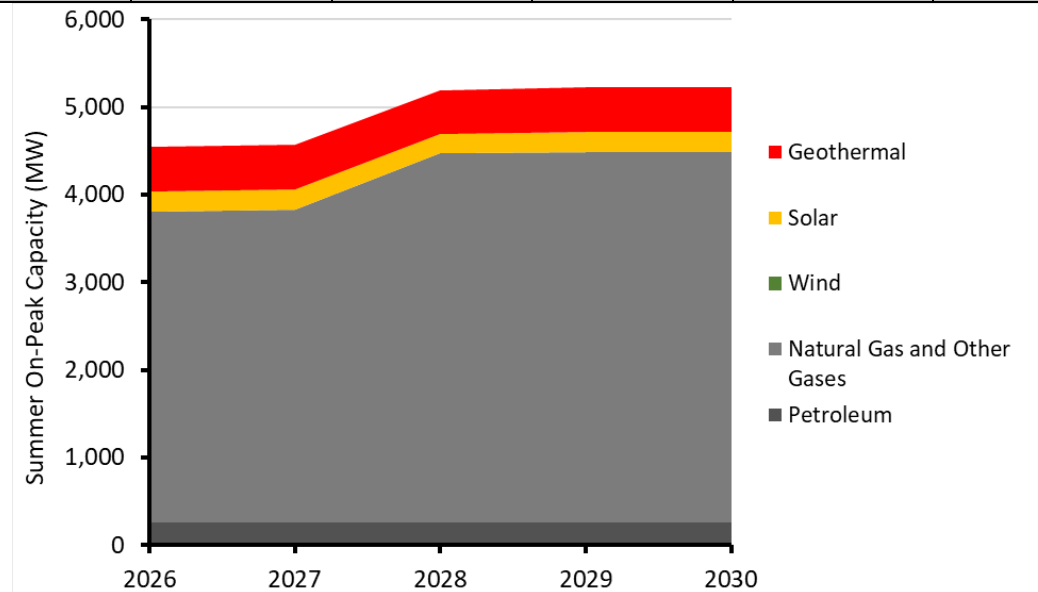
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins

The ARM is above the RML until 2035, the last year of the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00

* No prior results as the assessment area is new for the 2025 LTRA.

Demand

Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation

Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: [WECC Path Rating Catalog](#)) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

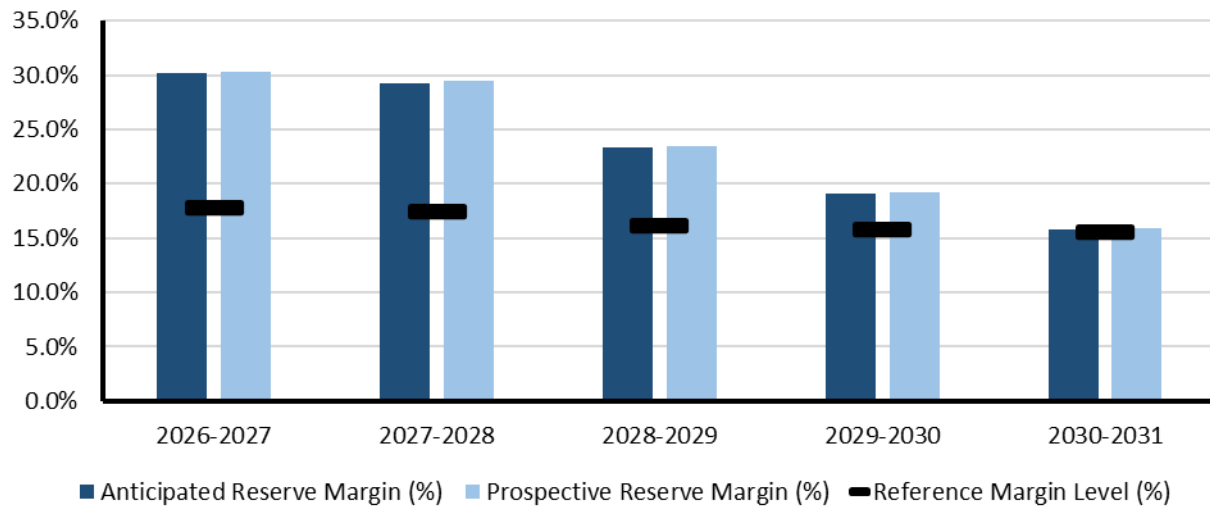


WECC-Northwest

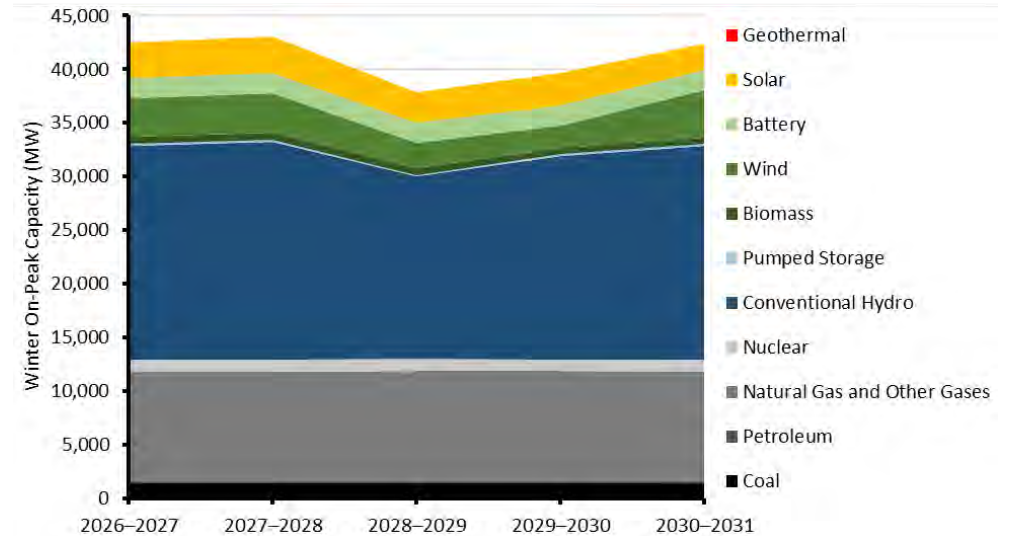
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the [WRAP Area Map](#).
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

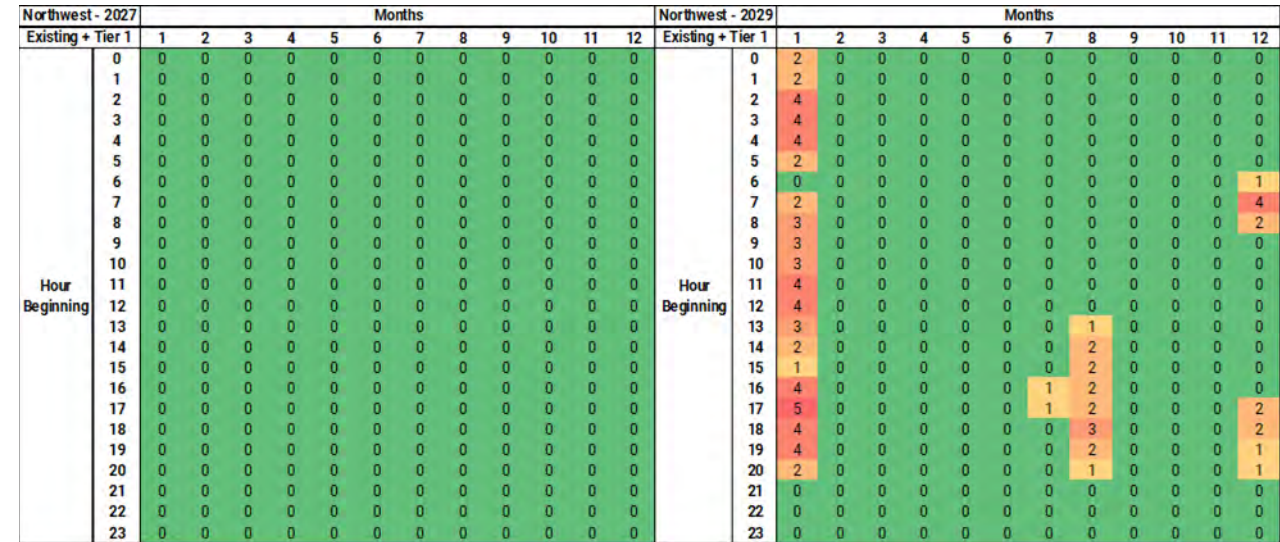
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

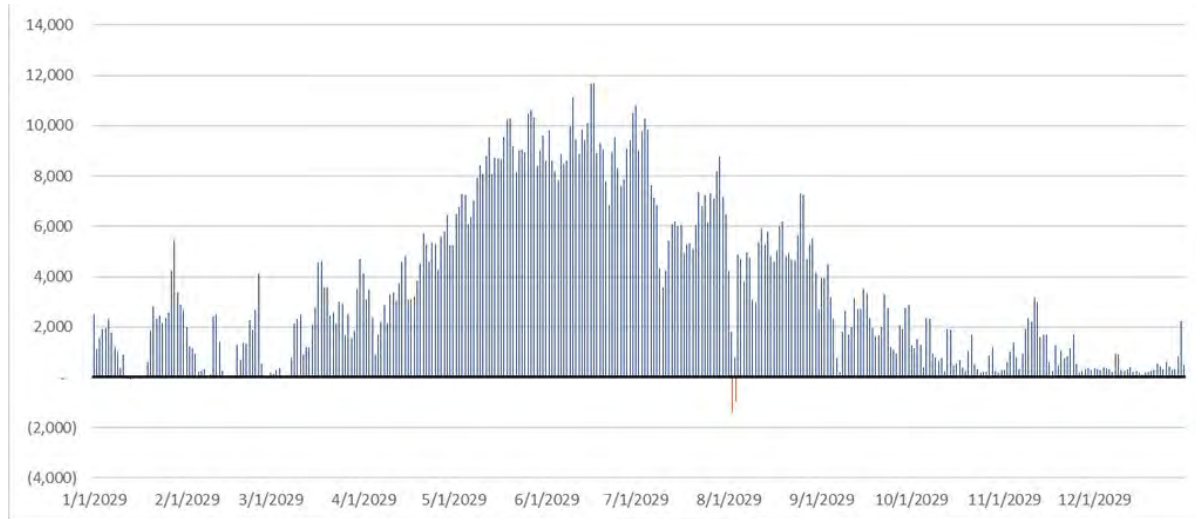
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.



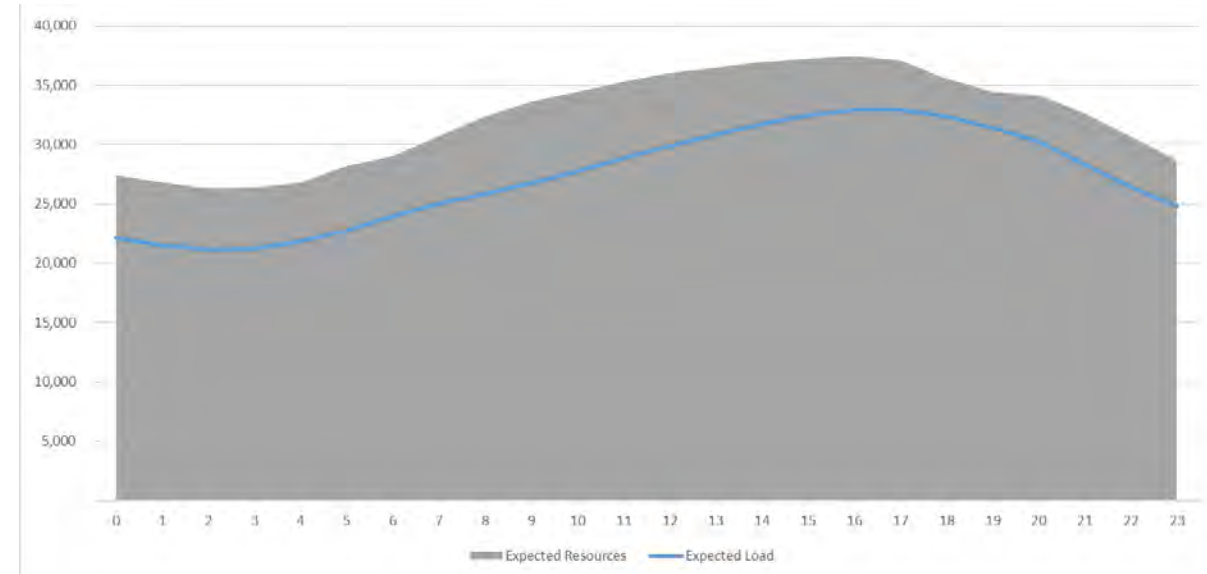
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest’s excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

Distributed Energy Resources

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state’s largest IOU has proposed a change that largely mirrors California’s revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer’s payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

Generation

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in

planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

Transmission: PacifiCorp’s [Blueprint transmission project](#) will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

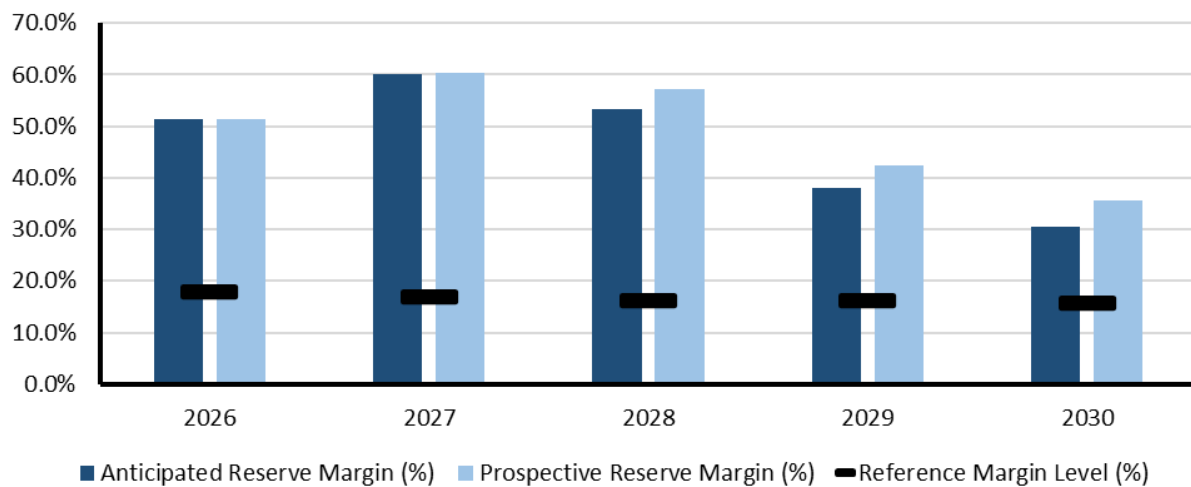


WECC-Rocky Mountain

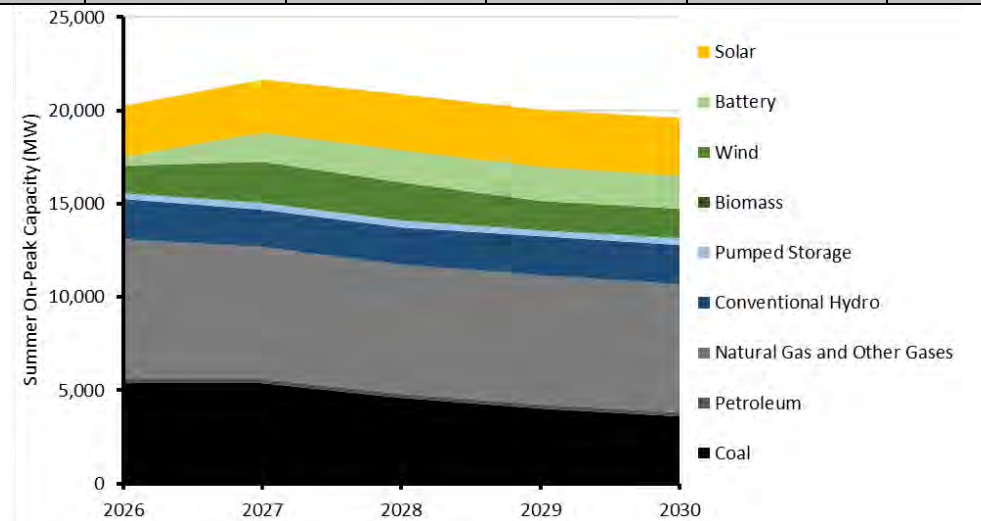
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration’s Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,004	14,338	14,565	15,021	15,442	15,873	16,306	16,764	17,207	17,297
Demand Response	287	290	293	285	287	290	293	296	298	301
Net Internal Demand	13,717	14,048	14,272	14,736	15,154	15,583	16,013	16,468	16,909	16,997
Additions: Tier 1	1,771	3,486	3,979	4,079	4,079	4,079	4,355	4,299	4,079	4,079
Additions: Tier 2	0	45	585	640	761	761	810	810	761	761
Additions: Tier 3	17	178	925	1,160	1,373	3,207	3,276	4,188	4,274	4,370
Net Capacity Transfers (WECC Model)	391	661	852	179	50	23	0	0	0	0
Existing-Certain and Net Transfers	18,979	18,995	17,884	16,278	15,696	14,882	14,721	14,329	14,143	14,098
Anticipated Reserve Margin (%)	51.3%	60.0%	53.2%	38.1%	30.5%	21.7%	19.1%	13.1%	7.8%	6.9%
Prospective Reserve Margin (%)	51.3%	60.3%	57.3%	42.5%	35.5%	26.6%	24.2%	18.0%	12.3%	11.4%
Reference Margin Level (%)	17.8%	17.0%	16.2%	16.1%	15.7%	15.2%	13.5%	11.9%	14.1%	13.9%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,383	5,376	4,623	4,034	3,585
Coal*	5,053	5,376	4,429	3,379	2,180
Petroleum	204	204	204	204	204
Natural Gas	7,522	7,083	6,897	6,902	6,902
Biomass	6	6	6	3	3
Solar	2,695	2,873	3,002	3,071	3,071
Wind	1,437	2,218	2,054	1,555	1,550
Conventional Hydro	2,139	2,043	2,029	2,116	2,116
Pumped Storage	346	340	340	346	346
Other	126	126	126	126	126
Battery	496	1,547	1,726	1,817	1,817
Unknown	6	5	5	6	6
Total MW	20,359	21,820	21,011	20,178	19,725
Total MW*	20,029	21,820	20,817	19,523	18,320

***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-Rocky Mountain

Planning Reserve Margins

The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo’s reserve margin is not used in WECC’s methodology for the LTRA.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00

*No prior results as the assessment area is new for the 2025 LTRA.

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

Demand

Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

Demand-Side Management

PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its [Demand Side Management & Beneficial Electrification Plan](#).

Distributed Energy Resources

BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

Generation

Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- **Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- **Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- **Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

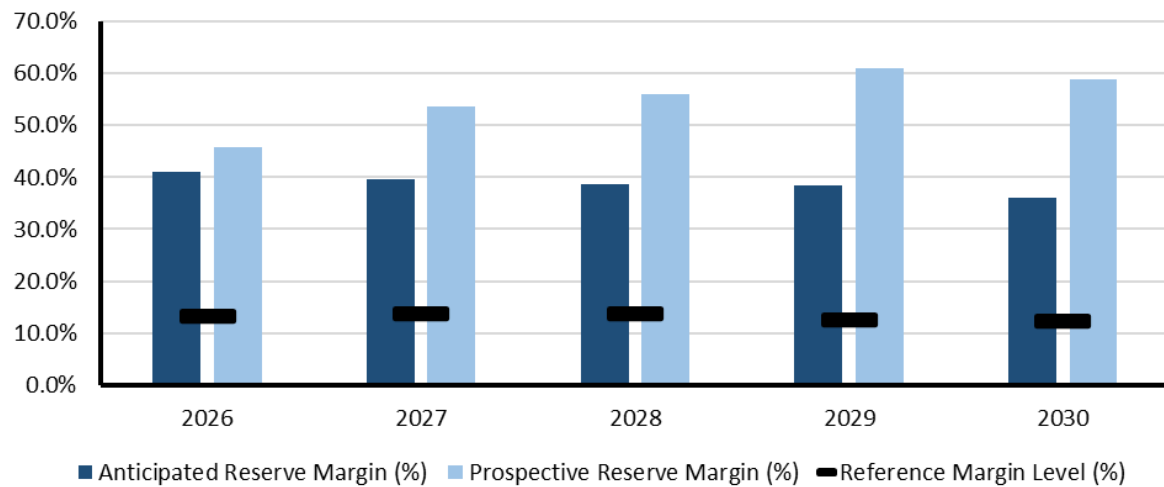


WECC-Southwest

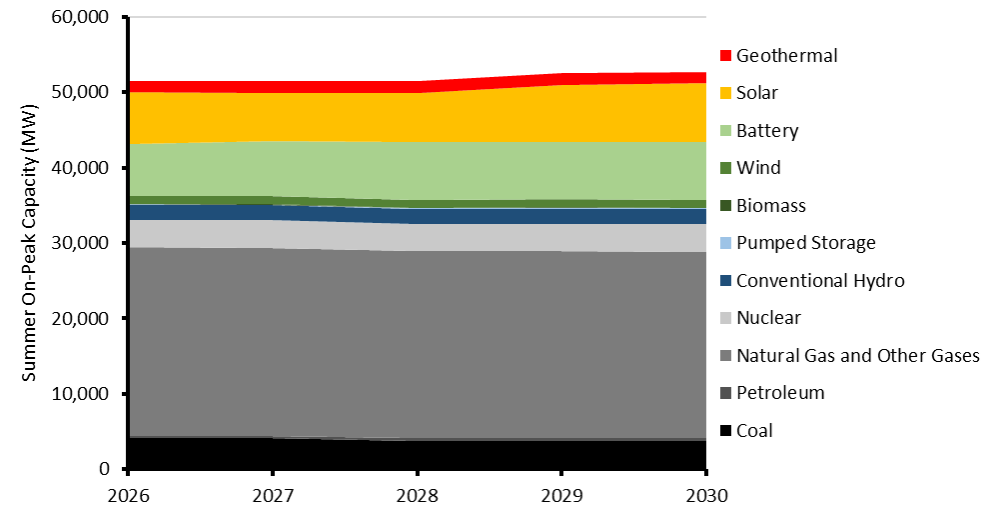
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421

*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-Southwest

Planning Reserve Margins

The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

Demand

The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

Demand-Side Management

In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system's capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

Distributed Energy Resources

BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

Generation

Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and

maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.

- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, [APS](#) has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load ⁴⁹ for the summer and winter of each year. ⁵⁰ Projected total internal demand is based on normal weather (50/50 distribution) ⁵¹ and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	Peak Season	Coincident / Noncoincident ⁵²	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-Alberta	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-Basin	Summer	Noncoincident	
WECC-British Columbia	Winter	Noncoincident	
WECC-California	Summer	Noncoincident	
WECC-Mexico	Summer	Noncoincident	

⁴⁹ [Glossary of Terms Used in NERC Reliability Standards.](#)

⁵⁰ The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

⁵¹ Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

⁵² Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area

Assessment Area	Peak Season	Coincident / Noncoincident ⁵²	Load Forecasting Entity
WECC-Northwest	Winter	Noncoincident	
WECC-Rocky Mountain	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources⁵³

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements⁵⁴

Prospective Resources: Includes all “anticipated resources” plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.⁵⁵

⁵³ Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

⁵⁴ Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

⁵⁵ Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to “Existing” with capacity contributions entered in “Expected-Other.” Once a “mothballed” unit is confirmed to be capable for commercial operation, capacity contributions should be entered in “Expected-Certain.”
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area’s planning processes):⁵⁶
 - Construction complete (not in commercial operation)
 - Under construction
 - Signed/approved Interconnection Service Agreement (ISA)
 - Signed/approved Power Purchase Agreement (PPA) has been approved
 - Signed/approved Interconnection Construction Service Agreement (CSA)
 - Signed/approved Wholesale Market Participant Agreement (WMPA)
 - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area’s planning processes):⁵⁷
 - Signed/approved Completion of a feasibility study
 - Signed/approved Completion of a system impact study
 - Signed/approved Completion of a facilities study
 - Requested Interconnection Service Agreement
 - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

⁵⁶ AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

⁵⁷ AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions

Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile

Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand

Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand

Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area.

The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment⁵⁸
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as “cascading blackouts,” the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.⁵⁹ NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),⁶⁰ which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
 - The BES does not experience instability, uncontrolled separation, cascading,⁶¹ and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.⁶²
 - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
 - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

⁵⁸ Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: [NERC Glossary of Terms](#)

⁵⁹ [BES Definition](#)

⁶⁰ NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.

⁶¹ NERC’s Glossary of Terms defines Cascading: “Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.”

⁶² NERC’s Glossary of Terms defines Disturbance: “1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.”

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the [Demand Assumptions and Resource Categories](#).

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a “target” or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.⁶³ This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
 - Planned (any of the following):
 - Permits have been approved to proceed

⁶³ https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement
- **Conceptual** (any of the following):
 - A line projected in the transmission plan
 - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
 - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
MISO	2025-2026 Summer: 8.1% Fall: 14.9% Winter: 19.1% Spring (2027): 26.2%	Planning Reserve Margin	Yes: Established Annually ⁶⁴	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0% ⁶⁵	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.0–13.4%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0% ⁶⁶	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	15.8–22.6%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	11.9–12.2%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	18.6–26.3%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0% ⁶⁷	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

⁶⁴ In MISO, the states can override the MISO PRM.

⁶⁵ The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

⁶⁶ The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

⁶⁷ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)

Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
SERC-East	15.0% ⁶⁸	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0% ⁶⁹	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0% ⁷⁰	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustent for non-modeled market considerations	ERCOT Board of Directors
WECC-Alberta	11.6–17.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁷¹
WECC-Basin	12.3–14.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-British Columbia	11.6–12.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-California ⁷²	19.2–20.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Mexico	7.0–9.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Northwest	15.5–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Rocky Mountain	15.7–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Southwest	12.2–13.7%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸

⁶⁸ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

⁶⁹ SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.

⁷⁰ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

⁷¹ WECC’s RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.

⁷² California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage>.

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

- 1. Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
- 2. Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.⁷³ A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.⁷⁴ Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.⁷⁵ Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.^{76,77}
- 3. Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.⁷⁸ Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.⁷⁹

⁷³ See the ERO's extensive IBR event reporting here: [NERC Major Event Reports](#)

⁷⁴ The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: [Industry Recommendation: Inverter-Based Resource Performance Issues](#).

⁷⁵ NERC's comprehensive initiatives to reduce IBR risks are detailed here: [IBR Quick Reference Guide](#)

⁷⁶ [NERC IBR Activities](#)

⁷⁷ [Order No. 901 Work Plan](#)

⁷⁸ [The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report](#)

⁷⁹ [Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott](#)

LTRA Recommendations and Ongoing ERO Actions

4. Mitigate fuel-related risks to electricity generation (fuel assurance): In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, provides planning guidance.⁸⁰

Initiative	Description	Product/Reliability Solution
<p>Cold Weather Reliability Standards and Activities</p>	<p>Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans.</p> <p>Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the <i>FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States</i> and respond to FERC directives.⁸¹ In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information filings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard’s ability to address reliability concerns and inform potential future modifications.</p>	<p>Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned</p>
<p>Inverter-Based Resources Strategy</p>	<p>NERC’s IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC’s extensive activities in each area are described in detail in the <i>IBR Activities Reference Guide</i>.⁸² NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks.</p> <p>NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.</p>	<p>Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars</p>

⁸⁰ Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: [NERC Reliability and Security Guidelines](#)

⁸¹ Refer to [Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination](#) and [Project 2024-03 Revisions to EOP-012-2](#) on NERC’s standards development page. [Project 2021-07](#)

⁸² [IBR Activities](#)

LTRA Recommendations and Ongoing ERO Actions

	<p>FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs.⁸³ Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.</p>	
<p>Natural Gas-Electric Interdependence Initiatives</p>	<p>Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, <i>Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System</i>, incorporated the <i>Design Basis for Natural Gas Study</i> developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry’s development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.⁸⁴</p>	<p>Reliability Guideline</p>
<p>Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.</p> <p>1. Develop the transmission network: ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.</p>		
<p>Initiative</p> <p><i>Interregional Transfer Capability Study (ITCS)</i></p>	<p>Description</p> <p>NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024⁸⁵. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025.⁸⁶ See Interregional Transfer Capability Study (ITCS) Canadian Analysis.</p>	<p>Product/Reliability Solution</p> <p>ERO Study and Recommendations</p>

⁸³ [FERC Order Issued November 17, 2022](#)

⁸⁴ [RSTC Approved Documents](#)

⁸⁵ NERC’s [Interregional Transfer Capability Study \(ITCS\) Final Report](#)

⁸⁶ [NERC’s Interregional Transfer Capability Study \(ITCS\) Canadian Analysis Final Report](#)

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Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.
2. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.
3. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators.⁸⁷
4. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.
5. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.⁸⁸

⁸⁷ [NERC ERS Measure 6 Forward Tech Brief](#)

⁸⁸ A comprehensive guide to ERO activities on DERs can be found here: [DER Activities](#)

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Initiative	Description	Product/Reliability Solution
Energy Assessments Initiatives	<p>NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this <i>2025 LTRA</i> to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC’s ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed.</p> <p>The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.⁸⁹ The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls.</p> <p>New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 <i>Energy Assurance with Energy Constrained Resources</i>.⁹⁰</p> <p>In other Reliability Standard development work, Project 2023-07 <i>Transmission System Planning Performance Requirements for Extreme Weather</i> requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.⁹¹</p>	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	<p>NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC’s extensive activities in each area are described in detail in the <i>DER Activities Reference Guide</i>.⁹²</p>	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	Description	Product/Reliability Solution
Ongoing Strategic Engagements	<p>NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.</p>	Constructive Partnerships

⁸⁹ [ERAWG](#)

⁹⁰ [Project 2022-03](#)

⁹¹ [Project 2023-07](#)

⁹² [DER Activities](#)

Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro's most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)