BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 1

DOE STANTON ORDER

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

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 (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)[3] is a coal-fired generator owned[4] and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.[5] The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,[6] and OUC anticipates placing Stanton Unit 1 in an "extended cold shutdown."[7] OUC expects to

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860M, Inventory of Operating Generators* (March 2026), (hereinafter EIA, *Form EIA-860M*) https://www.eia.gov/electricity/data/eia860m/. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW) and two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

[4] nFront Consulting LLC, *Orlando Utils. Comm'n 2025 Ten-Year Site Plan*, at 2-3, https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf [hereinafter nFront, *OUC 2025 Ten-Year Site Plan*].

[5] EIA, *Form EIA-860M*, *supra* note 3.

[6] *See, e.g.*, Michelle Lynch, *Fla. Mun. Elec. Ass'n, OUC's Bd. of Comm'rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025.

[7] nFront, *OUC 2025 Ten Year Site Plan*, at 6-2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be

make a determination as to Stanton Unit 2 by year end based on an Integrated Resource Plan currently underway.

EMERGENCY CONDITIONS

In its 2025 Long-Term Reliability Assessment (LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a "Normal Risk" for long-term energy adequacy.[8] Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.[9] Additionally, the 2025 LTRA maintains that 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.[10] As of April 2026, eight data centers are planned for construction in Florida.[11] Total peak demand is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.[12]

The 2025 LTRA also notes that, with "the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern."[13] Further, the 2025 LTRA states that:

> [t]he 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

---

greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Business Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[8] N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC, *2025 LTRA*].

[9] *Id.* at 6.

[10] *Id.* at 9.

[11] *See* Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), https://www.pewresearch.org/?p=299017.

[12] *See* Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

[13] *See* NERC, *LTRA*, *supra* note 9, at 116.

continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.[14]

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application[15] for 2.7 GW of specified resources (generating units) [16] and (ii) another[17] for 55 MW of back-up generators.[18] As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6: (i) Order No. 202-26-11 for specified resources,[19] and (ii) Order No. 202-26-15 for back-up generators.[20] OUC leveraged the 202(c) orders to meet demand during extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31, 2026 and February 6, 2026.[21] The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.[22] OUC had projected that it may not have sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.[23] In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.[24]

---

[14] *Id.*

[15] OUC 202(c) Application (Jan. 31, 2026).

[16] OUC Specified Resources (Exhibit A to 202(c) Application) (Jan. 31, 2026).

[17] OUC 202(c) Application – Backup Generators (Jan. 31, 2026).

[18] OUC 202(c) Application Exhibit A – Backup Generators (Jan. 31, 2026).

[19] *Orlando Utils. Comm'n,* Order No. 202-26-11 (Jan. 31, 2026).

[20] *Orlando Utils. Comm'n,* Order No. 202-26-15 (Jan. 31, 2026).

[21] *See* U.S. Env't Prot. Agency, CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (choose "Emissions" from "Data Type" dropdown; then choose "Daily Emissions" from "Data Subtype" dropdown; then choose "Unit (No Aggregation)" from the "Aggregation" dropdown; then click "Apply"; then click "Time Period" button and enter "January 31, 2026" as "Start Date" and February 6, 2026 as "End Date"; then click "Facility" and select "Curtis H. Stanton Energy Center"; then click "Apply Filter"; then click "Preview Data".).

[22] Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm'n, to The Honorable Chris Wright, Sec'y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/ouc-202c-application-backup-generators.

[23] *Id.*

[24] EIA, *Form EIA-923, Schedule 4: Generator Data* (Apr. 2026), https://www.eia.gov/electricity/data/eia923/.

According to NERC's 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.[25] It further notes that "[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South . . . ."[26] For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of "higher demand, outages, [or] derates in extreme conditions."[27]

Executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 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 extraordinary threat to our Nation's economy, national security, and foreign policy."[28] 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." In the subsequent Executive Order No. 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."[29]

Further, the Department of Energy 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," which was issued pursuant to the President's directive in Executive Order No. 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."[30]

---

[25] North American Electric Reliability Corporation, 2026 Summer Reliability Assessment, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[26] *Id.* at 4.

[27] *Id* at 10.

[28] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[29] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[30] DOE, RES. ADEQUACY REP.: EVALUATING THE RELIABILITY & SEC. OF THE U.S. ELEC. GRID (Jul. 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

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."[31] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Stanton Unit 1, 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, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the combination of increasing demand and shortage will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or power outages, presenting a risk to public health, and safety.

I have determined that, under the conditions specified below, continued availability of Stanton Unit 1 is necessary to best meet the emergency arising from increased demand for electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that Stanton Unit 1 will be available if needed to address emergency conditions, it shall remain in operation through September 1, 2026.

[31] 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).

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

A. From June 4, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is not placed in extended cold shutdown and is available to operate.[32] Following the conclusion of this Order, sufficient time for orderly ramp down will be permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with the allowances contained in this Order.

C. All operations of Stanton Unit 1 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. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By June 18, 2026, OUC is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Stanton Unit 1, consistent with this Order. OUC shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. OUC is directed to file with the Federal Energy Regulatory Commission any 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 Stanton Unit 1 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, Stanton Unit 1 shall not be considered a capacity resource.

[32] According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

H. This Order shall be effective from June 4, 2026, through September 1, 2026, with the exception of applicable compliance obligations in paragraph D.

I. OUC is directed to provide the Department at least fifteen days' prior advance notice in writing before any change in operational status or otherwise of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 4th day of June 2026.

Chris Wright

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

Florida Public Service Commissioners
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 2

DOE ORDER NO. 202-22-4

Department of Energy

Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource 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. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall 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. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 3

RMI ANALYSIS OF COAL PLANTS' THREATS TO RELIABILITY

Last Chance! $1 = $3 with our match. Donate now >>

ARTICLE August 12, 2025

Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

By Gabriella Tosado, Ashtin Massie, and Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

Customize Reject All Accept All

of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives — and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent — meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers, the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

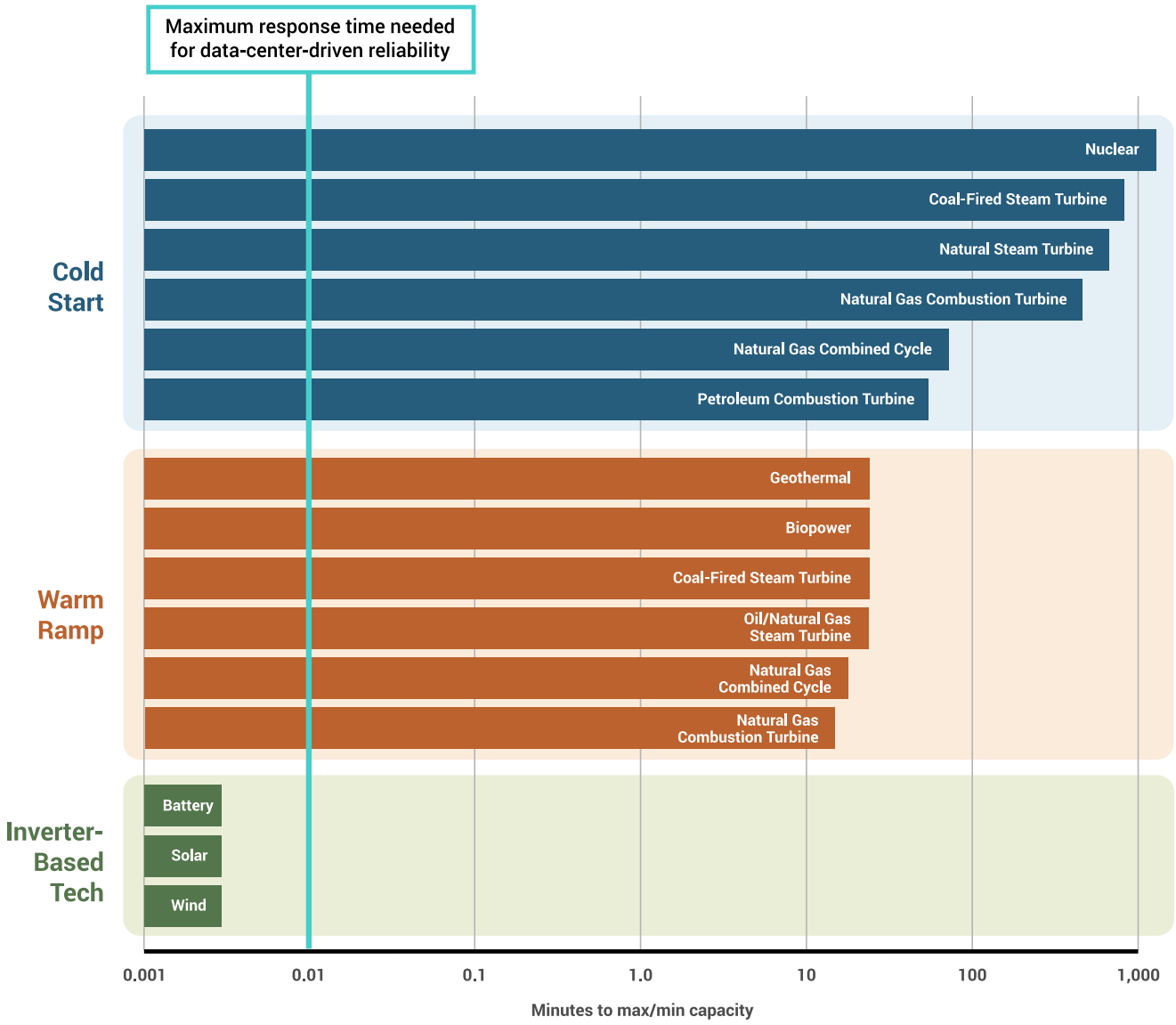
supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by independent market monitors in regions like MISO — which covers 15 US states and a Canadian province — where congestion-related market distortions have cost over $1 billion a year. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent *Incident Review and Guidance on Voltage-Sensitive Large Load Integration* describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is 4 percent per minute which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over 12 hours to reach max

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available — and scalable. For example, we recently found that more than 95 percent of future demand can be met with fast, scalable, and clean solutions:

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.
Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
	New load can be co-located with renewable energy at the

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent article, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources thoughtfully and intentionally, but propping up coal plants that are not suited for the job is a step in the wrong direction.

Related Topics

AI AND DATA CENTERS | COAL | DATA-CENTERS | ELECTRICITY | STATE POLICY

Authors

Gabriella Tosado
Senior Associate

Ashtin Massie
Senior Associate

Joe Daniel
Principal

We value your privacy

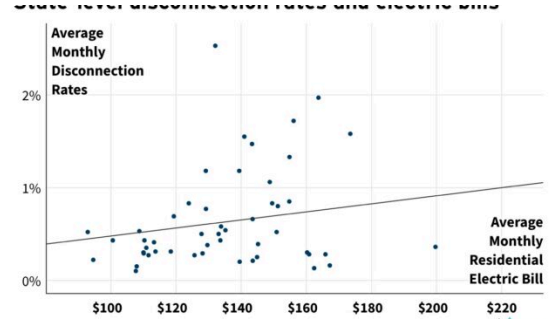
We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

Related Insights

Taking Cost Trackers Off Auto-Renew

ARTICLE ELECTRICITY

June 29, 2026



Disconnection Data Is Finally Available. What Does It Tell Us?

SPARK CHART ELECTRICITY

June 26, 2026

Clean Energy 101: The Changing Electricity Grid

101 ELECTRICITY

June 23, 2026

Clean Energy 101: How Rising

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

Our Mission

To transform the global energy system to secure a clean, prosperous, zero-carbon future for all.

Our Approach

Our Solutions

Get Involved

Events

Careers

Contact

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

© 2026 RMI | Privacy policy

We value your privacy

We use cookies to enhance your browsing experience, serve personalized ads or content, and analyze our traffic. By clicking "Accept All", you consent to our use of cookies. To learn more, please visit our Privacy Policy.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 4

DOE ORDER NO. 202-17-4 SUMMARY OF FINDINGS

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "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," to issue an order "requir[ing] . . . 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 emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or 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 . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 5

OUC 2026 TYSP

Orlando Utilities Commission

2026 Ten-Year Site Plan

Prepared by:
nFront Consulting LLC
April 2026

Table of Contents

1.0 Executive Summary 1-1
2.0 Utility System Description 2-1
2.1 Existing Generation System 2-1
2.2 Purchase Power Resources 2-4
2.3 Power Sales Contracts 2-4
2.4 OUC's Renewable Energy and Sustainability Initiatives and Community Activities 2-6
2.5 Transmission System 2-10
3.0 Strategic Considerations 3-1
3.1 Strategic Business Units 3-1
3.2 Florida Municipal Power Pool 3-3
3.3 Security of Power Supply 3-3
3.4 Environmental Performance 3-4
3.5 Community Engagement, Connecting with Our Customers, and Economic Development 3-4
4.0 Forecast of Peak Demand and Energy Consumption 4-1
4.1 Forecast Methodology 4-1
4.2 Base Case Forecast Assumptions 4-4
4.3 Base Case Load Forecast 4-5
4.4 High and Low Load Scenarios 4-7
5.0 Demand-Side Management 5-1
5.1 Energy Survey Programs 5-2
5.2 Residential Programs 5-3
5.3 Commercial/Industrial Programs 5-7
6.0 Forecast of Facilities Requirements 6-1
6.1 Existing Capacity Resources 6-1
6.2 Reserve Margin Requirements 6-2
6.3 Future Resource Needs 6-2
7.0 Supply-Side Alternatives 7-1
8.0 Economic Evaluation Criteria and Methodology 8-1
8.1 Economic Parameters 8-1
8.2 Fuel Price Forecasts 8-1
9.0 Analysis and Results 9-1

9.1 CPWC Analyses 9-1
10.0 Environemntal and Land Use Information 10-1
11.0 Conclusions 11-1
12.0 Ten-Year Site Plan Schedules 12-1

1.0 EXECUTIVE SUMMARY

This report documents the 2026 Orlando Utilities Commission ("OUC") Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-22.070 of Florida Administrative Code. OUC's Ten-Year Site Plan provides information required by this rule and consists of the following additional sections:

- Utility System Description (Section 2.0)
- Strategic Issues (Section 3.0)
- Forecast of Peak Demand and Energy Consumption (Section 4.0)
- Demand-Side Management (Section 5.0)
- Forecast of Facilities Requirements (Section 6.0)
- Supply-Side Alternatives (Section 7.0)
- Economic Evaluation Criteria and Methodology (Section 8.0)
- Analysis and Results (Section 9.0)
- Environmental and Land Use Information (Section 10.0)
- Conclusions (Section 11.0)
- Ten-Year Site Plan Schedules (Section 12.0)

In December 2020 OUC finalized an Electric Integrated Resource Plan ("EIRP"), which provides a roadmap to enable OUC to achieve its goal of Net Zero Carbon by 2050, as well as interim goals of 50% carbon emissions reductions by 2030 and 75% carbon emissions reductions by 2040 as compared to 2005 levels. The first major steps outlined to achieve these carbon reduction targets were to convert one coal fired generating unit (Stanton Energy Center Unit 1) to cleaner-burning natural gas no later than 2025, convert the other coal unit (Stanton Energy Center Unit 2) to cleaner-burning natural gas no later than 2027, and install 1,524 MWac of solar and 350 MW of energy storage by 2030. OUC anticipates refreshing its EIRP within the next 12 months.

In September 2021, OUC purchased the Osceola Generating Station ("OGS"), which better enables large-scale solar farms by mitigating the intermittency of solar power, the utility's most viable source of renewable energy. The purchase of OGS also allows OUC to place its oldest coal-fired power plant, Stanton Unit 1 located in East Orange County at the utility's Stanton Energy Center ("SEC"), into extended cold shutdown by the end of May 2026 in lieu of converting this unit to cleaner burning natural gas. The OGS purchase further provides OUC an extra layer of resiliency with emergency backup fuel to help prevent power disruption events as seen in Texas in early 2022 and elsewhere in the United States since then.

The purchase of OGS from Genova, a Texas-based private ownership group, will further diversify OUC's generation fleet. OGS is comprised of three separate turbines, known in the industry as "peakers," which can turn on and off quickly as opposed to the larger, Stanton Unit 1 turbine that requires more fuel and takes many hours to turn on. OGS can power up in just minutes. The acquisition of OGS and placing Stanton Unit 1 into extended cold shutdown will change OUC's generation portfolio, making it more flexible in managing intermittent resources, and most importantly, as OUC's primary goal, reducing carbon dioxide ("CO_2") emissions.

OUC remains committed to meeting the EIRP's objectives, which include increasing solar energy and other renewable resources for electric generation, and reducing carbon dioxide emissions by 50% by 2030 and 75% in 2040 as compared to 2005 levels before reaching Net Zero emissions by 2050.

OUC continues to increase solar energy, having added approximately 256 MW since late 2020. Meanwhile, OUC is exploring energy storage solutions and the use of other clean energy assets in addition to investing in electrification programs that would result in further carbon dioxide reductions and cleaner air for our community.

OUC continues to assume responsibility for supplying all of the City of St. Cloud ("St. Cloud") loads through calendar year 2042. Load forecasts for OUC and St. Cloud have been integrated into one forecast, and details of the aggregated load forecast are provided in Section 4.0, including base-case growth, high-growth, and low-growth scenarios.

OUC has contracts to provide power to the City of Winter Park ("Winter Park") through calendar year 2026, the City of Mount Dora ("Mt. Dora") through 2030, the City of Chattahoochee ("Chattahoochee") through 2027, and Lakeland Electric ("Lakeland") through 2026. The power OUC is currently planning to provide to Winter Park, Mt. Dora, Chattahoochee, and Lakeland is summarized in Section 2.0.

OUC is a member of the Florida Municipal Power Pool ("FMPP"), which consists of OUC, Lakeland, and the Florida Municipal Power Agency ("FMPA") All-Requirements Project. Power for OUC is supplied by units owned entirely by OUC, as well as units in which OUC maintains joint ownership and power purchases. OUC's total capacity as of January 1, 2026, including capacity from units owned by OUC, St. Cloud's entitlement to Stanton Energy Center Unit 2, and OUC's current power purchases (including natural gas, landfill gas, and solar resources), provides total net summer capacity of approximately 2,593 megawatts ("MW") and total net winter capacity of approximately 2,502 MW[1].

As discussed throughout this Ten-Year Site Plan, consideration of OUC's current generating resources (including existing and planned power purchase agreements) and OUC's current base-case load forecast indicate that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035.

[1] Net seasonal capacity ratings as of January 1, 2026. Includes capacity owned by OUC and St. Cloud, as well as OUC's contractual power purchases.

2.0 UTILITY SYSTEM DESCRIPTION

At the turn of the 20th century, John M. Cheney, an Orlando, Florida judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100-kilowatt ("kW") generator. Twenty-four-hour service began in 1903. The population of the City of Orlando ("City") had grown to roughly 10,000 by 1922, and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a $975,000 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately-owned utility. The bond issue passed by a margin of almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando acquired Cheney's company and its 2,795 electricity and 5,000 water customers for a total initial investment of $1.5 million.

In 1923, OUC was created by the state legislature as an independent statutory commission with its own Board as a part of the government of the City. OUC was granted full authority to operate electric and water municipal utilities. The business was a paying venture from the start. By 1924, the number of customers had more than doubled. When Orlando citizens took over operation of their utility, the City's population was less than 10,000; by 1925, it had grown to 23,000.

OUC has full authority over the management and control of the electric and waterworks plants in the City, those it has built or acquired and has been approved by the Florida legislature to offer these services in Osceola County, as well as Orange County. OUC's charter has been amended a number of times since 1923 and it now allows it to undertake, among other things, the acquisition, construction, operation, and maintenance of electric generation, transmission, and distribution systems, chilled water systems, as well as water production, transmission, and distribution systems, to meet the requirements of its customers. In addition, OUC offers a variety of energy and compliance services through interlocal agreements with other municipal utilities.

In 1997, OUC entered into an Interlocal Agreement with the City of St. Cloud in which OUC assumed operational control of St Cloud's electric systems and the responsibility for supplying all of St. Cloud's loads for the 25-year term of the agreement, which added an additional 150 square miles of service area. OUC also assumed management of St. Cloud's existing generating units and power purchase contracts. This agreement has been extended through 2042.

2.1 Existing Generation System

Presently, OUC has ownership interests in four electric generating plants, which are described further in this section. Table 2-1 summarizes OUC's generating facilities as of January 1, 2026, which include:

- Stanton Energy Center Units 1 and 2, Stanton A, and Stanton B.
- Indian River Plant Combustion Turbine Units A, B, C, and D[2].
- Osceola Generating Station Units 1, 2, and 3.
- Florida Power & Light Company ("FPL") St. Lucie Unit 2 Nuclear Generating Facility.

[2] As discussed throughout this report, OUC has purchased the steam units at the Indian River site; however, the units are currently in extended cold shutdown and, therefore, are not included in calculations of OUC's available capacity.

Table 2-1 Summary of OUC Generation Facilities

(As of January 1, 2026)

PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL		FUEL TRANSPORT		COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	NET CAPABILITY	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	16[1]	18[1]
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	16[1]	18[1]
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	83[2]	88[2]
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	83[2]	88[2]
Stanton Energy Center	1	Orange	ST	BIT	NG	RR	PL	07/87	Unknown[3]	453[4]	453[4]
Stanton Energy Center	2	Orange	ST	BIT	NG	RR	PL	06/96	Unknown	352[5]	352[5]
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	184[6]	189[6]
Stanton Energy Center	B	Orange	CC	NG	FO2	PL	TK	02/10	Unknown	292	307
St. Lucie	2	St. Lucie	NP	UR	--	TK	--	06/83	Unknown	60[7]	62[7]
Osceola Generating Station	1	Osceola	GT	NG	FO	PL	TK	12/2001	Unknown	157	157
Osceola Generating Station	2	Osceola	GT	NG	FO	PL	TK	12/2001	Unknown	157[8]	157[8]
Osceola Generating Station	3	Osceola	GT	NG	FO	PL	TK	06/2002	Unknown	157	157

[1]Reflects an OUC ownership share of 48.8 percent.
[2]Reflects an OUC ownership share of 79.0 percent.
[3]As discussed throughout this 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026.
[4]Reflects 100 percent OUC ownership as of January 1, 2026.
[5]Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 3.4 percent.
[6]Reflects an OUC ownership share of 28.0 percent.
[7]OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.
[8] Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280-acre site contains Units 1 and 2, as well as Units A and B, and the necessary supporting facilities. Stanton Unit 1 was placed in commercial operation on July 1, 1987, followed by Stanton Unit 2, which was placed in commercial operation on June 1, 1996. Both units are fueled primarily by pulverized coal and can generate up to approximately 70 MW each on natural gas, utilize natural gas igniters, and operate at emission levels that are within the Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP") requirement standards for sulfur dioxide ("SO2"), nitrogen oxides ("NOx"), and particulates ("PM"). Stanton Unit 1 is a 453 MW net coal-fired facility; as of January 1, 2026 OUC owns 100 percent of this unit, which provides approximately 453 MW of capacity to the OUC system. Stanton Unit 2 is a 463 MW net coal-fired generating facility; OUC maintains a 71.6 percent (approximately 336 MW) ownership share of this unit. OUC anticipates placing Stanton Unit 1 into extended cold shutdown by the end of May 2026 and converting Stanton Unit 2 to be capable of operating only on natural gas by the end of 2027; OUC is in the process of determining the final timing of these changes.

OUC entered into an agreement with Kissimmee Utility Authority (KUA), FMPA, and Southern Company-Florida LLC ("SCF", an affiliate of Southern Power), which governs the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center that began commercial operation on October 1, 2003. NextEra Energy purchased Southern Power's interest in Stanton A, and as such, discussion of Stanton A's ownership structure refers to NextEra Energy throughout this Ten-Year Site Plan, as appropriate. OUC, KUA, FMPA, and NextEra Energy are joint owners of Stanton A, with OUC maintaining a 28 percent ownership share (and purchases 52 percent), KUA and FMPA each maintaining 3.5 percent ownership shares, and NextEra Energy maintaining the remaining 65 percent of Stanton A's capacity. Stanton A is a 2 X 1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual-fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel.

Stanton B is a 1 X 1 combined cycle utilizing General Electric combustion turbines. Stanton B is dual-fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. OUC is the sole owner of Stanton B.

The Indian River Plant is located four miles south of Titusville on US Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant Energy in 1999, with OUC subsequently repurchasing the units in 2012. Given their current condition (the units are currently in extended cold shutdown), the Indian River steam units do not provide generating capacity for OUC, but do provide OUC with future options for new generating capacity. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent (approximately 16 MW summer and 18 MW winter, per unit) in Indian River Units A and B, as well as a partial ownership share of 79 percent (approximately 83 MW summer and 88 MW winter, per unit) in Indian River Units C and D.

OUC has a 6.08951 percent ownership share in St. Lucie Unit 2 (a nuclear generating facility operated by FPL), providing approximately 60 MW of summer and 62 MW of winter generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied by St. Lucie Unit 1 and half by St. Lucie Unit 2.

St. Cloud has an entitlement to capacity from Stanton Unit 2 associated with its purchase through FMPA (related to FMPA's participation in the Stanton II Project). FMPA's ownership stake in Stanton Unit 2 through the Stanton II Project is 23.2 percent, and St. Cloud's purchase from FMPA's Stanton Unit 2 ownership is 14.67 percent (providing approximately 15 MW).

The Osceola Generating Station is comprised of three separate turbines, with each unit providing 157 MW of summer and winter capacity. OUC anticipates completion of all necessary transmission system improvements to allow all three of the Osceola Generating Station units to provide power to OUC by the summer 2026 peak period.

2.2 Purchase Power Resources[3]

OUC has a purchase power agreement ("PPA") with NextEra Energy for 80 percent of NextEra Energy's 65 percent ownership share of Stanton A through December 2031, as well as an additional PPA with NextEra Energy to purchase the remaining 20 percent of NextEra Energy's 65 percent ownership share of Stanton A through December 2028.

2.3 Power Sales Contracts

OUC has the following contractual power sales:

- a contract to provide power to the City of Winter Park ("Winter Park") through 2026.
- a contract to provide power to the City of Mt. Dora ("Mt. Dora") through 2030.
- a contract to provide power to the City of Chattahoochee ("Chattahoochee") through 2027.
- a contract to provide power to Lakeland Electric ("Lakeland") through 2026.

For purposes of this Ten-Year Site Plan, OUC has assumed the winter and summer capacities and annual energy presented in Table 2-2 will be provided to Winter Park, Lakeland, Mt. Dora, and Chattahoochee.

[3] OUC's renewable power purchases are discussed in Section 2.4 of this Ten-Year Site Plan.

Table 2-2 Projected Annual Summer and Winter Peak Capacity (MW) and Annual Net Energy for Load (GWh) to be Provided to Winter Park, Mt. Dora, Chattahoochee, and Lakeland

	SUMMER MW			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	17	26	9	100
2027	0	26	9	0
2028	0	27	0	0
2029	0	27	0	0
2030	0	27	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
	WINTER MW			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	17	20	7	50
2027	0	20	7	0
2028	0	20	0	0
2029	0	20	0	0
2030	0	21	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
	ANNUAL GWh			
Calendar Year	Winter Park	Mt. Dora	Chattahoochee	Lakeland
2026	98	108	37	35
2027	0	110	37	0
2028	0	112	0	0
2029	0	114	0	0
2030	0	116	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
All Summer and Winter MW are non-coincident. All rounded to nearest MW or GWh.				

2.4 OUC's Renewable Energy and Sustainability Initiatives and Community Activities

OUC is actively incorporating renewable technologies into its diverse generation portfolio and taking other steps to reduce carbon dioxide ("CO_2") emissions. In 2020, OUC established new clean energy goals to achieve a 50 percent reduction in CO_2 emissions by 2030[4], a 75 percent reduction in CO_2 emissions by 2040[5], and net-zero CO_2 emissions by 2050. These targets require investments in technologies such as solar photovoltaic ("PV") and energy storage. Such technologies will allow OUC to meet customer electricity demand while reducing CO_2 emissions.

Renewable energy, energy efficiency, sustainability and community engagement are crucial to achieving OUC's clean energy goals. OUC's recent renewable energy and sustainability initiatives, as well as activities in the community and customer education programs, are discussed in the following subsections[6].

2.4.1 Solar and Batteries

2.4.1.1 Customer Facing Solar and Battery Programs

OUC actively provides more opportunities for its customers to participate in solar projects and programs. These initiatives include TruNet Solar, a Battery Storage Rebate, OUCommunity Solar, SunChoice©, and the Solar Thermal rebate Program.

- TruNet Solar is OUC's net metering program whereby all energy delivered by OUC to the customer will be billed using standard retail rates and customers are credited for all energy supplied by them to OUC based on a credit rate per kWh until June 30, 2030 that equals the community solar energy rate (currently 4.567¢/kWh) and the levelized fuel charge thereafter. This amount is subject to change based on market conditions. This program went into effect July 1, 2025 and is for customers not grandfathered under the Solar Net Metering program (including those taking over an account on or after July 1, 2025, from a grandfathered customer). The existing rooftop solar customers that have submitted a complete interconnection application for their current premises before June 30, 2025 ("grandfathered customer") will be reimbursed for excess energy generation as follows:
    - The credit rate per kWh until June 30, 2045, shall equal the sum of the non-fuel base and fuel charge (currently 10.65¢/kWh for residential customers). This amount is subject to change based on market conditions.
    - For residential customers the non-fuel base charge shall not include the conservation adder for all additional kWh over 1,000.
    - For time of use ("TOU") customers the energy supplied to OUC by the customer will be measured and credited by distinct TOU time periods.
    - After June 30, 2045, the credit rate per kWh shall equal the levelized fuel charge.
- OUC offers rebates for battery storage system purchase and installation to customers who export excess energy under the Community Solar Energy Rate. Eligible customers with rooftop solar systems sized below 20 kW can receive a rebate of $150 per rated kWh up to $2,000 for adding battery storage to their solar installations. The battery storage must be directly

[4] Compared to a 2005 CO_2 baseline.
[5] Compared to a 2005 CO_2 baseline.
[6] Please refer to Section 5.0 of this Ten-Year Site Plan for discussion of OUC's conservation and demand-side management programs.

connected to the customer's solar system to qualify for this incentive. This program follows a successful pilot program conducted in 2019.

- Residential and commercial customers enrolled in the OUCommunity Solar program can get access to sustainable, maintenance-free solar energy without the costs associated with installing panels on their homes or businesses. Those enrolled subscribe at a small premium to receive between 10 percent to 100 percent of their energy from OUC's solar resources.
- In 2024, OUC introduced its SunChoice© program, which allows commercial customers to demonstrate their commitment to the deployment of utility scale solar arrays and secure Renewable Energy Certificates ("RECs") as evidence of their commitment to offsetting their consumption with renewable energy sources. The program costs are in addition to a customer's standard utility bill. Customers subscribe a percentage of their actual consumption in 10 percent tranches. Customers pay tiered prices associated with their subscription level. OUC retires the RECs in the customer's name annually based on their subscription level and the actual quantity of energy they consume.
- Residential customers participating in the Solar Thermal Program receive a rebate of $900 for installing a solar water heating system. Federal incentives, including the investment tax credit, are available to eligible customers to help minimize costs of solar PV, energy storage and solar thermal systems.

2.4.1.1 Utility Scale Solar and Batteries

As part of a pilot program, a 4-megawatt, 8-megawatt-hour utility scale battery energy storage system ("BESS") was installed at OUC Substation 29 in east St. Cloud. Substation 29 is connected to transmission lines that support the solar array at the Harmony Solar Energy Center.

In order to better utilize solar energy and increase its reliability during cloudy weather, OUC has embarked in designing its own advanced algorithms and control schemes. These algorithms are being tested at OUC's Grid Integration Lab ("GIL"), formerly known as "Nanogrid", a living laboratory for testing the interoperability of multiple distributed energy resources and the ability to self-operate at OUC's Gardenia facility. GIL currently is comprised of 64 kWdc of floating solar, 100 kW/129kWh lithium iron phosphate batteries, 120kW DC fast charging, 194 kW DC-coupled battery fast charger, 28kW of Level 2 EV charging, and 16kW/64kWh flywheel energy storage. The site is used in partnership opportunities with UCF and local startups, such as developing an intelligent control system and testing capacitors for enhanced microgrid operations. The research into dispatch and control of assets at GIL will enable solar to become more reliable during intermittent weather as well as help to drive down costs for energy storage.

OUC completed installation of a 1.6 MWac floating array on a Florida Department of Transportation ("FDOT") pond in late 2025. Plans are in place to develop a roadmap for a larger deployment of floating solar throughout OUC's territory.

Table 2-3 presents a summary of OUC's existing contracts for purchases of solar power.

Table 2-3 OUC's Existing Solar Purchase Power Contracts

Facility	Operational Year	Purchased Capacity (Nameplate; MWac)
Stanton Energy Center	2011	5.1
Kenneth P. Ksionek	2017	8.9
Harmony	2020	34.0
Taylor Creek	2020	74.5
Harmony II	2024	74.5
Storey Bend	2024	74.5

2.4.2 Landfill Gas

Methane or landfill gas is created by the decomposition of wet organic waste under anaerobic, or oxygen-less, conditions in a landfill. This gas is considered a renewable energy source because the anaerobic digestion process continues as waste materials are constantly added to the landfill.

In partnership with Orange County, OUC captures methane gas emissions from county landfill cells and pipes it to the Stanton Energy Center where it is co-fired with coal. In addition to helping to reduce greenhouse gas emissions, this 8 MW project has the potential to displace more than three percent of the coal burned at the Stanton Energy Center. It will be capable of producing in excess of 100,000 megawatt-hours ("MWh") of reduced-emissions power – offsetting about 44,000 tons of coal each year.

Table 2-4 presents a summary of OUC's existing contracts for purchases of landfill gas power.

Table 2-4 OUC's Existing Landfill Gas Purchase Power Contracts

Facility	Operational Year	Purchased Capacity (MW)
Port Charlotte/Collier	2011	4.00
Monarch Hills	2016	6.00
Holopaw JED	2017	9.00

2.4.3 Carbon Reduction

With more than 720 vehicles – ranging from plug-in hybrids to bucket trucks – OUC's fleet logs more than 2.7 million miles annually. OUC currently has ten line trucks employing the Jobsite Energy Management System (JEMS). JEMS is a great application for hybrid technology since much of the vehicle's work is done when stationary. The hybrid diesel-electric system allows the main engine to be turned off while crews operate entirely off the battery, therefore reducing the production of greenhouse gases and reducing fuel consumption for idling. OUC reduces its carbon footprint by using alternative fuels, purchasing electric vehicles and recycling automotive products to help the environment. As part of an overall plan to reduce emissions in its fleet, OUC uses "B20" – a blend of 80 percent petroleum diesel and 20 percent biodiesel –

a clean-burning alternative fuel made from new or used vegetable oils and animal fats, including recycled cooking grease. B20 has been integrated seamlessly into the fueling system without any changes to vehicles or fuel storage and distribution equipment. OUC uses biodiesel at the Pershing Fleet Center and the Gardenia site. OUC has installed two 10,000-gallon fuel tanks that store E85 fuel at its Pershing and Gardenia sites.

OUC's Fleet Division has incorporated several eco-conscious policies, including the use of earth-friendly products and special care taken to dispose contaminated fuels according to environmental standards. Tires, batteries, and oil filters are recycled through vendors, while antifreeze and motor oil are handled on-site. OUC recycles about 20,000 gallons of used oil each year. OUC also has a vehicle idling policy that requires the engine to be turned off after five minutes of idling.

Embracing fuel-efficient technology as a commitment to green initiatives, OUC has grown the commitment to include fourteen all-electric cars, two plug-in electric hybrids, and twenty-six hybrids in the fleet.

OUC has installed more than 300 public charging stations. In July 2023, OUC commissioned the Robinson Mobility Recharge Hub with 21 high-speed chargers located in downtown Orlando. An OUC-led partnership that includes the City of Orlando, Orange County and Power Electronics, the manufacturer of the EV charging equipment, received a $500,000 grant from the Florida Department of Environmental Protection to build the station. A second Hub with 6 fast charging stations was installed near the Orange County Convention Center in September 2024. OUC has provided an additional 40 level 2 charging stations to meet the needs of its employees and fleet.

2.4.4 Energy Efficiency and Sustainability

OUC's commitment to efficiency and sustainability is also demonstrated by Reliable Plaza, OUC's energy and water efficient center on West Anderson Street. Reliable Plaza earned Gold Leadership in Energy and Environmental Design ("LEED") certification in 2009, recognizing the 10-story administration and customer service center as the "Greenest Building in Downtown Orlando." Reliable Plaza also holds a Florida Water Star certification, a voluntary program for new and existing construction that encourages water efficiency in appliances, plumbing fixtures, irrigation systems and landscapes. Reliable Plaza utilizes a number of environmentally friendly features designed to use 28 percent less energy and 40 percent less water than a similarly sized facility.

OUC's 24-acre St. Cloud Operations & Maintenance Facility is the first net-zero energy campus for a Florida utility, combining state-of-art technology with sustainability. The campus uses 50 percent less energy and 40 percent less water than conventional facilities of similar size. It supports permanent fleet and logistic operations, as well as being designed to accommodate a future new substation based on projected load growth. It will also serve as an alternative emergency response center for OUC operations.

OUC's Commercial Indoor Lighting Program helps customers convert old, inefficient lighting to high-efficiency technology. Since launching the program in 2002, more than 45 million kWh and 10.5 MW demand has been saved in buildings like public schools, churches, theme parks and hospitals, resulting in annual energy cost savings of about $16 million.

The Home Utility Report Program ("HUR") is a free service offered to OUC customers designed to help them save energy, water, and money. The report compares a customer's energy and water consumption to similar households, as well as provides personalized tips that show how much they can save by changing their behavior. Participants receive a free HUR monthly email report or bi-monthly printed report. To administer the HUR program, OUC works with a third-party company that helps utilities meet their efficiency goals through effective customer engagement. There is also an online portal available to customers to obtain additional information on how to save energy and water.

2.5 Transmission System

OUC's existing transmission system in Orlando consists of 31 substations interconnected through approximately 340 miles of 230 kV and 115 kV lines. OUC is integrated into the Florida Reliability Coordinating Council ("FRCC") regional transmission grid through multiple utilities. Additionally, OUC is responsible via an Interlocal Agreement for planning, operating and maintaining St. Cloud's nine substations interconnected through approximately 85 miles of 230 kV and 69 kV transmission lines.

3.0 STRATEGIC CONSIDERATIONS

OUC incorporates a number of strategic considerations while planning for the electrical system. This section provides an overview of a number of these strategic considerations.

3.1 Strategic Business Units

OUC 's Electric and Water operations is organized into three strategic business units: Electric & Water Production ("EWP"), Transmission ("TRAN") and Electric and Water Distribution ("EWD") that report to a Chief Operating Officer.

3.1.1 Energy and Water Production Business Unit

The EWP business unit has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. EWP will only be profitable if it can produce electricity and water that is competitively priced in the open market. In line with this strategy, OUC is continually studying strategic options to improve or reposition its generating assets.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's longstanding intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant (which is now retired), followed by the acquisition of an ownership share in Lakeland Electric's McIntosh Unit 3 coal-fired unit (which is now retired) in 1982. In 1983, OUC acquired a share of the St. Lucie Unit 2 nuclear unit. OUC also modified the Stanton Energy Center coal units to allow the units to offset a portion of their coal usage with natural gas. Additional details of OUC's generating facilities are presented in Table 2-1 and Schedule 1 of Section 12.0 of this Ten-Year Site Plan.

OUC's fuel diversity is further enhanced by the renewable energy resources that are discussed in detail in Section 2.4 of this Ten-Year Site Plan.

In 2020 the Business Unit led the Electric Integrated Resource Plan that calls for a review of OUC's generation needs in light of the growing penetration of distributed energy resources, such as solar power, and a call to move to Net Zero Carbon by 2050. Florida-specific factors were taken into consideration because renewable resources are limited relative to other regions in the country and could impact fuel diversity. Currently, wind, hydroelectric and geothermal are not economically and/or technically viable in Florida – and biomass and landfill gas, while technically viable, are only available in small quantities. While solar is feasible, it poses intermittency challenges, and back up resources will be necessary to ensure that power is always available. OUC will continue to evaluate wind-by-wire generation and monitor emerging clean technologies such as hydrogen, offshore wind and small modular nuclear power plants. [7]

Table 3-1 summarizes OUC's existing (owned and purchased) capacity by fuel type, including renewable energy resources. The ability to generate up to approximately 70 MW while operating on natural gas in each of Stanton Units 1 and 2 further enhances the percentage of generating capacity fueled by natural gas.

[7] OUC anticipates refreshing its Electric Integrated Resource Plan within the next 12 months.

Table 3-1 Capacity (MW) Owned and Purchased by OUC by Fuel Type
(As of January 1, 2026)

PLANT NAME	WINTER CAPACITY						SUMMER CAPACITY					
	Coal	Nuclear	Gas/ Oil	PV	LFG	Total	Coal	Nuclear	Gas/ Oil	PV	LFG	Total
Stanton[1][2]	682		1,055			1,737	682		1,028	7		1,717
Indian River			213			213			197			197
St. Lucie		62				62		60				60
Osceola[3]			471			471			471			471
Other (MW)					19	19				129	19	148
Total (MW)	682	62	1,739	0	19	2,502	682	60	1,696	136	19	2,593
Total (percent)	27%	2%	69%	0%	1%	100%	26%	2%	65%	5%	1%	100%

[1] " "Coal" capacity includes OUC's share of the landfill gas burned in Stanton Units 1 and 2.
[2] Stanton Units 1 and 2 can each generate up to approximately 70 MW while operating on natural gas., which is included in "Gas/Oil" capacity
[3] Reflects Osceola Generating Station Units 1 through 3. Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.

3.1.2 Transmission Business Unit

The OUC Transmission Business Unit is responsible for the planning, engineering, construction, and maintenance of all substations and lines operating at 69kV or higher. To maintain reliable and economic service and proactively plan for the future, OUC plans and evaluates various upgrades to its transmission system.

3.1.3 Energy and Water Distribution Business Unit

OUC's EWD business unit focuses on providing OUC's customers with the safest and most reliable electric service possible.

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, more than 68 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree-trimming program that minimizes tree-related service disruptions.

3.2 Florida Municipal Power Pool

In 1988, OUC joined Lakeland Electric and FMPA's All-Requirements Project members to form the Florida Municipal Power Pool ("FMPP"). Later, KUA joined FMPP. Over time, FMPA's All-Requirements Project has added members as well. FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch provides savings to all parties via reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is three years and automatically renews until terminated by the consent of all participants.

OUC's participation in FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

3.3 Security of Power Supply

OUC currently maintains interchange agreements with other utilities in Florida to provide electrical energy during normal and emergency conditions. The reliability of the power supply is enhanced by metered interconnections with other Florida utilities, including twelve interconnections with Duke Energy Florida, four with KUA, two with Tampa Electric Company, two with FPL, one with Lakeland Electric, one with Central Florida Tourism Oversight District, two with St. Cloud, and one with NextEra. Along with enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida.

3.4 Environmental Performance[8]

As the quality of the environment is important to Florida, and especially important to the tourism-driven economy of Central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate its generating units with emission levels below those required by permits and licenses by equipping its power plants with the best environmental protection systems available at the time of their construction and continuously enhancing these systems over time. Unit 2 is the first unit of its size and kind in the nation to use selective catalytic reduction ("SCR") to remove nitrogen oxides ("NO_X"). Using SCR and low-NO_X burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it. Stanton A incorporates environmentally advanced technology and enables OUC to diversify its fuel mix while adding more flexibility to OUC's portfolio of owned generation and purchased power. Stanton B further contributes to OUC's environmentally responsible portfolio of generating resources.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. Additionally, OUC has installed natural gas igniters for both Stanton 1 and Stanton 2, eliminating the use of No. 6 fuel oil and reducing the amount of coal burned during operations when economical to do so.

Further demonstrating its environmental commitment to clean air, OUC has harnessed the power of methane. Methane gas, if not captured and burned, is released into the atmosphere and is considered 20 times more intense than carbon dioxide in terms of possible global warming effects. As discussed in Section 2.4.2, OUC has signed a contract to burn methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Both Stanton 1 and Stanton 2 have the capability of burning methane. Additionally, OUC receives the energy generated from the burning of methane gas collected from the Port Charlotte/Collier, Holopaw JED and Monarch Hill Landfills.

OUC has also voluntarily implemented a product substitution program not only to protect workers' health and safety but to minimize hazardous waste generation and to prevent environmental impacts. The Environmental Compliance and Safety Departments constantly review and replace products to eliminate the use of hazardous substances. To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

3.4.1 Emphasis on Sustainability

OUC completed its first greenhouse gas inventory for the entire company in 2008 and updates the inventory annually. This report helps OUC analyze how it impacts the environment and details operating emissions. The report is made available to customers, typically commercial, that request it.

3.5 Community Engagement, Connecting with Our Customers, and Economic Development

3.5.1 Community Engagement

As Orlando's hometown utility, OUC is committed to helping the community it serves. Individuals and organizations know they can rely on the utility when it matters most–through board involvement, support,

[8] Please refer to Section 2.4 of this Ten-Year Site Plan for a detailed discussion of OUC's renewable generating technologies and other environmental initiatives.

employee volunteerism and more. OUC supports more than 300 nonprofit and business-based organizations that focus on the four pillars of social impact, environmental stewardship, education and economic development and participates in nearly 150 events each year, while employees annually volunteer between 5,000 and 10,000 hours in the community. Many events incorporate sustainability messaging, encouraging the efficient use of energy and water.

From unique solar pavilions and sculptures at high visibility locations like Lake Lorna Doone Park, Inter & Co Stadium and St. Cloud's Lakefront Park, to H_2OUC Hydration Stations at parks and neighborhood centers, OUC's commitment to sustainability can be seen all around town.

OUC also supports a diverse group of business chambers within its service territory, including Ivanhoe Village, Lake Nona, , and Hispanic chambers. While actively engaging with the St. Cloud, Indian American, Prospera, Caribbean, Haitian, African-American, and Asian communities. OUC is also actively involved with economic gardening and business development organizations such as Orlando Economic Partnership, Downtown Orlando Partnership, Central Florida Hotel and Lodging, and technical associations.

In 2021, OUC unveiled a 200-square-foot "home" on wheels that served as a model of sustainable living for anyone to experience. The Tiny Green Home, a partnership between OUC, the City of Orlando and Orlando Science Center ("OSC"), was an educational resource showcasing the benefits of energy and water conservation, renewable energy, sustainability rebates, vehicle electrification, composting, growing food and sustainability programs offered by OUC, the city and OSC. Stationed on OSC property in Loch Haven Park, the micro-dwelling also includes a functioning roof-top solar array and a rain barrel to collect and conserve water, among other green features visitors could add to their own homes. The Science Center was responsible for staffing, operating and maintaining the exhibit, which was accessible with admission. Retired in 2025, the Tiny Green Home hosted more than 20,000 visitors through community events and OSC tours.

In 2023, OUC partnered with the Orlando Science Center to launch a new interactive exhibit that focuses on water and energy conservation. Designed to educate and engage, the exhibit highlights the importance of managing these essential resources responsibly and explores innovative solutions for the future. Through an interactive and gamified experience, concepts such as IoT (Internet of Things), Smart Grid technology, Micro Grids are introduced. The "Power Play" game challenges visitors to route power to a city as quickly and efficiently as possible. Participants select where a city's buildings, solar panels and power plants are connected to create a balanced power grid. The goal: link all elements so power production and consumption are balanced. The fast-paced game provides a practical and engaging introduction to energy management and the complexity of maintaining a reliable power grid.

3.5.1.1 Utility and Community Volunteerism

OUC launched Project CARE, its utility assistance fund, in 1994. The program, managed by Heart of Florida United Way 2-1-1, a local, nonprofit organization, provides rapid response to customers in need through case management. Since its inception, Project CARE has allocated more than $8 million, assisting more than 30,000 households and thousands of families and individuals. For every $1 donated by customers, OUC contributes $2 to the program.

With the onset of the COVID-19 pandemic in 2020, OUC took immediate steps to help impacted customers. OUC suspended electric and water disconnections for nonpayment and waived late payment

fees with a $12.1 million customer-relief package that included $7.5 million to lower electric fuel rates; a $2.6 million contribution to Project CARE, in partnership with the City of Orlando; $1.5 million for utility bill payment assistance to qualified small businesses; and $500,000 for new OUC Power Pass customers. Payment plans and deferred payment arrangements were offered to customers for up to 12 months depending on qualifying criteria. By the end of 2020, more than 6,500 customers accessed Project CARE funds while more than 1,800 small businesses took advantage of the OUC relief program targeting them. Meanwhile, OUC connected more than 2,800 customers to the federal government's Low-Income Home Energy Assistance Program ("LIHEAP") and helped more than 40,000 set up payment plans, amounting to millions of dollars in deferred revenues.

With prices rising for so many products and services, we know our customers are feeling the strain. That's why OUC is continuing to invest in OUC's utility assistance program—Project Care. Below shows the assistance provided in the last three fiscal years. In OUC's fiscal year 2025, OUC provided more than $229,000 in utility assistance to help nearly 1,000 households with a plan to increase funding for fiscal year 2026.

In FY2023: October 1, 2022 – September 30, 2023

- Total Assistance Amount: $799,864
- Households Assisted: 2,694
- Average Assistance Amount: $296.91

In FY2024: October 1, 2023 – September 30, 2024

- Total Assistance Amount: $302,682
- Households Assisted: 1,020
- Average Assistance Amount: $296.75

In FY2025: October 1, 2024 – September 30, 2025

- Total Assistance Amount: $229,064
- Households Assisted: 721
- Average Assistance Amount: $317.70

Regarding volunteerism, OUC's Proud Volunteer program encourages and rewards employees for their volunteer work in the community. Employees volunteer over 6,000 hours every year and help support a variety of nonprofit organizations in the community including quarterly volunteer events specifically for employees with one of the four events focused on environmental clean-up.

The annual OUC Charity Golf Tournament has raised over $1 million for more than 87 Central Florida non-profits since its inception in 1995. In 2025, OUC raised $58,000 for 4 central Florida non-profit organizations in support of OUC's four pillar approach to community investment.

3.5.1.2 Water Color Project

Since 2006, OUC has hosted the Water Color Project, a conservation-themed art program that encourages students to highlight the importance of saving water through their artwork. While fourth- and fifth-grade students compete to have their artworks featured in OUC's Water Conservation Calendar, middle and high school students paint water-inspired themes on rain barrels. Their completed works are displayed in

a traveling exhibit, judged and later sold in a silent auction, with the proceeds going back to the winning schools' art programs. More than 40,000 students from over 250 local schools have participated in this program. Launched in 2020, OUC now hosts an annual public auction of the rain barrels painted by the local middle and high school students who participated in our annual Water Color competition. Proceeds directly benefit the Orange County Public Schools Visual Arts Department.

With the success of the Water Color Project, OUC launched the program in St. Cloud and rebranded it as the Watts Savings Project with a focus on energy conservation. OUC kicked off this inaugural project in 2025 and since then have had 14 schools and almost 2,000 students participate in the calendar contest. Each year, OUC employees vote for the top 13 calendar designs, which are featured in the yearly calendar. With such a successful launch, OUC will expand this program in the next school year to grow and include additional schools in its territory.

3.5.1.3 Project AWESOME

OUC and the Orlando Science Center deliver energy and water conservation workshops to every fifth grader in OUC's service territory via Project AWESOME (Alternative Water & Energy Supply; Observation, Methods & Education). The educational program promotes both water and energy conservation through a hands-on curriculum using content approved by OUC that meets Common Core Standards. As part of an electric and water conservation and alternative sources educational program, the projects include modeling the flow of electricity from coal and solar power sources through substations before being distributed to industrial and residential consumers and designing and creating a drip irrigation system for a city park. Project AWESOME, which launched in 2009, delivers two 90-minute classroom workshops (one per semester), as well as hands-on labs and pre- and post-classroom activities. Energy is covered as part of the earth science section that's taught in the fall semester while water is the focus of the spring semester's life science section. Due to COVID and schools turning to virtual learning in early 2020, Project AWESOME workshops shifted to online. In 2021, OSC shifted back into the classrooms but continues to offer a virtual option to all the teachers for convenience and accessibility. Since 2009, more than 139,000 students have gone through the curriculum.

3.5.1.4 Strategic Partnerships Promote Awareness

OUC partners with highly visible, professional sports teams in Central Florida to highlight OUC's commitment to sustainability, conservation, and impactful economic development efforts. As of 2026, some of these partnerships include: Orlando Magic, Orlando City Soccer Club, and United States Tennis Association ("USTA").

Our current partnership with the Orlando Magic focuses on promoting energy and water conservation through interactive activations at games, in-game LED banners and videos. In addition to our game-day activities, we also partner with the Magic to host B2B events designed to promote commercial conservation efforts. These events provide an opportunity to engage businesses customers and partners in energy and water efficiency practices, offering valuable insights and resources to help them reduce their environmental impact while also driving cost savings.

In the past, OUC played a significant role in the design phase of the Orlando Magic's LEED-certified home, the Kia Center (formerly the Amway Center), contributing to its energy and water efficiency features. We highlighted the facility's LEED certification and sustainability efforts through educational signage and digital media. Additionally, from 2019 to 2022, OUC supported the Orlando Magic's Community Assist Program—donating one tree for every assist made by a Magic player during the season. Now concluded,

it was a key initiative that helped plant more than 5,000 trees in the Central Florida community. Today, OUC continues to focus on its commitment to energy and water conservation in collaboration with the Orlando Magic.

Since 2015, OUC has been the official and exclusive electric and water utility partner for Orlando City Soccer Club and Orlando Pride. Within Inter&Co Stadium (formerly Exploria Stadium), OUC branded all water fountains and showcases the savings that can be achieved through sustainability initiatives. Both permanent and transitional signage highlights energy and water efficiency features incorporated into the facility. In November 2020, OUC unveiled "Gyration," a soccer-ball shaped solar sculpture designed by UCF students. The sculpture generates 1,264 kWh of clean energy annually, achieving net-zero carbon output. In 2023, OUC also installed EV charging equipment at the stadium. Additionally, OUC serves as the presenting sponsor for the Club's sustainability initiative, which is focused on maintaining a zero-waste facility.

OUC's partnership with the USTA at the Home of American Tennis in Lake supports sustainability. OUC is exclusively designated as the "Official Sustainability & Utility Sponsor" and highlights energy, water, and emerging technology through initiatives such as EV charging stations, hydration stations, and solar arrays on the roofs of shade pavilions. The facility hosts more than 250 events and attracts approximately 400,000 unique visitors per year.

3.5.1.5 OUC Empowerment Zone

OUC has a multi-year commitment to revitalizing one of the most economically disadvantaged zip codes in its territory, 32805. The Empowerment Zone program encourages broad-based economic prosperity and community support, ensures improved access to OUC programs and improves the overall health and wellness of the community. In short: OUC's Empowerment Zone seeks to build thriving communities by leveraging OUC's resources and partnerships to enhance three pillars: educational opportunities, sustainable housing, and health and wellness. Examples include:

- Virtual Tutoring Programs with ELEVATE Orlando, which OUC supported by donating a total of 20 laptops to two middle schools. OUC employees participated in weekly sessions tutoring ten students.
- In 2019, OUC employees raised $42,000 for New Image Youth Center ("NIYC"), as part OUC's annual workplace giving campaign, OUCares. NIYC works with at-risk students in grades K-12 in the Parramore community and provides academic support, social development, health and wellness programs and crisis intervention services. In addition, OUC donated 25 laptops to the New Image Youth Center to support their education assistance programs.
- OUC created a pre-apprenticeship program to meet the goals of creating career opportunities vs. job opportunities; prioritizing diversity, equity and inclusion; and raising median incomes for the community. This approach is helping to combat unemployment; increase livable wages; eliminate financial burdens on students; and provide a measurable impact. To date, OUC has sponsored three pre-apprenticeship cohorts. All 11 members of the inaugural class, who graduated in October 2021, landed full-time jobs paying more than $30,000 a year, plus benefits and paid apprenticeship training classes to help them with career advancement. Seven students graduated from the 2022-23 program, with participants attending classes at PKZ and West Oaks Academy. The 2024 and 2025program graduated 19 students.

- OUC is working with Career Source of Central Florida to provide opportunities for high school students to learn about careers in the utilities industry hosting site tours and providing speakers to assist in raising awareness of the utility industry as a potential employer.
- OUC partnered with the Central Florida Housing Trust - Parramore Asset Stabilization Fund on an affordable housing project. OUC's contribution to the initiative included improving the efficiency of 83 residential units, with such upgrades as attic insulation and weather stripping, duct work repair, irrigation improvements, LED lighting, Energy Star® windows, hybrid water heaters and energy efficient AC systems. Residents of these homes realized annual utility savings of approximately $575 annually.
- OUC also is developing cost-saving programs and providing conservation education through neighborhood advisory councils. OUC partnered with LIFT Orlando, a local nonprofit, to help revitalize the City of Orlando's Lake Lorna Doone Park, which is in the Empowerment Zone. OUC's is sponsoring the recently built 4,800-square-foot OUC Solar Pavilion at Lake Lorna Doone Park and EV charging stations and hydration stations in the park. The pavilion will serve as a hub for community events and activities while providing 42kWac of renewable energy.
- With the goal of inspiring young and old residents to read books, OUC and community partners set up nine Little Free Libraries in the Parramore neighborhood since May of 2021. Painted by OUC volunteers, each Little Free Library resembles a miniature wooden house with a pitched roof and glass door that opens to two shelves of books, two dozen or so in all. To date more than 4,000 books have been distributed across the eleven libraries.
- Recognizing that personal health and wellness are critical to community revitalization, OUC has undertaken a number of initiatives to improve health and wellness in the Parramore Empowerment Zone. Working with Shepherd's Hope, OUC sponsors the HEAL program – promoting healthy eating and an active lifestyle with focus on topics from obesity and mental health to cardiovascular risks and nutrition. Average attendance of 33 senior citizens and 27 high school students was observed in sessions held in 2022 and 2023. Activities including distribution of more than 3,600 pieces of educational material and 252 bags of fresh food, along with completion of 15 home energy audits, resulted from the HEAL program. Additionally, attendees were connected with Shepherd's Hope who offer free healthcare and condition management programs as part of their mission.

3.5.2 Connecting with Our Customers

From providing better online access to their consumption history to designing convenient and effective conservation programs, OUC arms customers with the information and tools they need to optimize the efficiency of their homes and businesses. This includes the community outreach previously discussed in this report as well as a mix of new technologies and programs designed to provide customers with the information, control and options they desire.

3.5.2.1 Self-Service Options

OUC's informational website, self-service portal and automated phone system are transacted with millions of times each year by many customers.

Customers are able to find tips, videos on ways to save, and frequently asked questions regarding their services. Through their myOUC online profile, they are able to pay their bills, make service requests, request payment extensions and more. The Usage Dashboard and OUC Power Pass program continue to

drive adoption of the website. The site is mobile friendly and accessible from a range of devices including tablets and smartphones.

3.5.2.2 Traditional Media and Digital Outreach

OUC utilizes a comprehensive, multi-channel approach to reach our customers through print, digital, television, radio, social, outdoor media and community partnerships. By diversifying and targeting media, OUC can effectively reach the right customer with the right message. Campaigns cover a range of topics, from safety to storm prep to sustainability. These campaigns reinforce OUC's commitment to showing customers how to reduce their energy and water use and ultimately their utility bills while promoting programs and initiatives important to the community.

Launched in February 2024 and still actively running OUC's "Get Green" campaign continues to drive engagement and increased rebate redemptions through targeted and segmented messaging. By tailoring email content to specific customer segments, including water and energy usage patterns, and utilizing seasonal scheduling, the campaign remains relevant and resonates across a wide audience. The strategic use of data, including DMV information for EV rebates and detailed customer attributes like home age and income to ensure the right messages reaches the right customers.

The campaign continues to leverage multiple channels to maximize its reach, including Meta ads, Google Display Ads, OTT streaming ads, direct-to- home postcards and organic social media posts. A dedicated landing page on OUC's website (ouc.com/getgreen) is the central hub for the campaign, driving significant traffic. In 2025, the site had 59,591 sessions and an active user base of 54,883. Additionally, email marketing remains a key focus, with monthly emails and follow-ups along with A/B testing ensuring optimal communication. The campaign's success is reflected not only in its rebate redemptions but also in its ability to generate long-term energy and water savings, proving to be a valuable tool in OUC's conservation efforts.

3.5.2.3 Connections

Connections is a monthly newsletter sent to all OUC customers whether they receive a paper statement or e-bill. The newsletters are posted on www.OUC.com and feature OUC's programs, community events, sustainability initiatives, and energy- and water-saving tips.

3.5.2.4 OUC Blog

In 2019, OUC launched a blog called OUConnect (www.oucblog.com). On OUConnect, customers can learn ways to save energy, water and money and how OUC is creating innovative products and services to meet the ever-growing needs of Central Florida. Customers will also read articles about community initiatives, as well as profiles on employees making a difference both at work and in their hometowns.

3.5.2.5 OUConnect E Newsletter

In April 2019, OUC launched a monthly email newsletter to all residential and commercial customers with email addresses (170,000). This newsletter keeps customers informed and connected to OUC's programs, products, provides conservation tips and more.

3.5.2.6 Social Media

Instagram, Facebook, X (formerly Twitter), YouTube, and NextDoor allow OUC to update customers about the Commission's community involvement, as well as provide them with conservation tips, outage and

restoration updates, and other need-to-know, real-time information that may affect them. Social media platforms also serve as additional customer service outlets, allowing customers to notify OUC about issues needing quick resolution, and provide additional opportunities for the Commission to build interactive relationships with customers and potentially diffuse negative situations.

3.5.2.7 Digital Meters

OUC's entire service area was upgraded with nearly 370,000 digital electric and water meters. The digital meters are easier to read and provide detailed information about customers' daily energy and water use. Meters can be monitored remotely, which reduces costs and time while ensuring an accurate and timely reading for the customer. Remote monitoring also allows OUC to better predict and prevent outages and restore power faster. OUC created Florida's first meter farm consisting of 120 electric meters and four water meters at its Pershing facility. The farm provides information and shows OUC exactly how updates are installed to ensure the meters are working correctly.

3.5.2.8 OUC Power Pass Program

OUC Power Pass is a program that allows customers to pay-as-you-go or pay in advance for utility services allowing the option of avoiding deposits, late fees and a monthly bill. Statistics have shown that pay-before-consumption programs result in less electricity and water usage because customers are more aware of how much they are using. Customers can check on their electric bill or water usage every day using the OUC Power Pass portal or receive alerts via text, email and/or phone. More than 20,000 customers are enrolled in the program to date.

3.5.2.9 Usage Dashboard

Digital meter technology allows customers to monitor electric and water consumption on 15 minute basis instead of waiting until the end of the month to receive their bills. The ability to track usage patterns and adjust lower energy bills was one of the items most frequently requested by OUC customers. To accommodate their needs, OUC released the OUC Usage Dashboard to most residential customers through their myOUC online profile. Because the new system also provides high-consumption alerts via email, changes in usage can be made immediately, and costs can be kept in check.

3.5.2.10 Online Rebate Application

OUC is continuing the use of software through the next few years and implemented a new software solution for rebate processing in 2022. OUC provides an online rebate application tool for customers to apply for rebates without the hassle of paperwork. It offers more convenience for customers and reduces transaction time. Customers are able to access the tool through their myOUC online profile.

3.5.2.11 PowerShift & PeakShift

In 2019, OUC launched a pilot project to offer Time of Use ("TOU") rates – internally known as PowerShift – to explore the viability of extending a new rate structure as an option for customers. The pilot formally ended in 2023. During an exploratory phase, OUC gauged interest from each customer segment and ultimately accepted 700 customers to participate in the pilot. Beginning in April 2021, the 700 pilot customers were billed utilizing On-Peak (2 p.m.-8 p.m.) and Off-Peak rates, the latter being the lowest, offering customers the opportunity to save on their monthly bills and to also smooth OUC's power demand curve. At the conclusion of the pilot, OUC offered participating customers the option to continue on the TOU rate. Of the initial 700 customers enrolled, 474 have chosen to remain in the program past the pilot phase. As part of the pilot, OUC created numerous marketing and communication materials to

ensure customers are equipped with the tools and resources to be successful in the program. Feedback gathered via quarterly customer surveys helped shape the program messaging OUC is using data from these surveys, as well as other data points and metrics gathered during the pilot to determine the future of TOU rates.

Building on the success of the PowerShift Pilot Program, in December of 2024, the OUC Board of Commissioners approved Peak*SHIFT*, a multiyear pricing plan to empower customers with new opportunities to save money, better align costs with how electricity is used and help shift OUC's system electric peak. As OUC implements this modernized pricing structure, the utility will continue to engage with customers and the community. The program has three primary components:

- **DemandLevel Pricing**: Anticipated to go live in November 2026, this program reduces variable non-fuel energy cost per kWh and adds a tiered fixed charge to encourage reducing distribution peak demand (the point where each residential and small commercial customer's usage is at its highest 15-minute average within the month), rebalance costs and reflect individual customers' usage of the electric grid.
- **TruNet Solar**: Anticipated to go live in November 2026, this program adjusts compensation for rooftop solar customers who apply for solar interconnection after June 30, 2025 to reflect industry changes and address systemwide cost equity concerns to ensure affordability of rates for all OUC customers.
- **Shift & Save**: Anticipated to go live in 2027, introduces as time-of-day pricing plan to enable customers to save money by shifting part of their electricity usage to "off-peak" periods for those that want additional incentives to save money.

3.5.2.12 Outage Alerts

OUC launched the first phase of its OUC Alerts program with Outage Alerts in December 2017. The system allows customers to receive information about service outages, including the cause and an estimated restoration time, via text, voice or email.

3.5.2.13 Billing Alerts

In January 2019, the second phase of OUC's Alerts program expanded to include Billing Alerts. The new feature lets customers set an alert, via text, email or voice, to let them know when their new bill is ready to view and when payment is due. This alert, along with Outage Alerts, launched in 2017, are among new "two-way communication" initiatives OUC has introduced to provide customers. Future OUC Alerts program phases to consider include consumption notifications and marketing messages.

3.5.3 Economic Development

Orlando has undergone a radical transformation over the years to diversify its economy and attract high-wage positions in technology, medicine, life sciences, and modeling and simulation. With Orlando's increasing emphasis on recruiting, retaining and expanding commercial customers, OUC has become a major player in the region's economic development. Working in partnership with Enterprise Florida, the Orlando Economic Partnership, and city and county governments, the utility is attracting more companies to Orlando and St. Cloud and helping them grow into vital and valuable members of the business community.

To attract large businesses that enhance the vitality of the community, OUC offers two rates. For large power users who qualify, OUC is able to negotiate its already-affordable rates to fit their business needs. The Economic Development Rider ("EDR") is available to new or expanding businesses representing select

target industries. Companies must add a minimum of 500 kW demand of new electric load and must create at least 25 new jobs at or above the 150 percent median income level to qualify. The Commercial Industrial Service Rider ("CISR") is available to companies that have minimum load of 2,000 kW or greater, served by a single meter. Companies must provide validation of a lower rate offering outside OUC's service territory to qualify.

Details of these rates and other incentives are outlined at www.oucpowersgrowth.com – a website that assists site selectors and businesses seeking to locate and learn more about Orlando and OUC. The site includes property search functionality and is mobile friendly.

4.0 FORECAST OF PEAK DEMAND AND ENERGY CONSUMPTION

OUC prepares a set of sales, energy, and demand forecast models each year to support its budgeting and financial planning process as well as long-term planning requirements. In preparing the forecasts, OUC uses internal records, company knowledge of the service territory and customers, and economic projections. OUC draws on outside expertise as needed. S&P Global provides economic projection data. Itron provides the primary forecasting software, analysis of end-use equipment saturation and efficiencies, and technical expertise. In this forecast, the National Renewable Energy Laboratory was utilized to provide adoption curves used to project rooftop solar within OUC's service territory while the midpoint of multiple different industry electric vehicle curves was used to forecast electric vehicle sales.

4.1 Forecast Methodology

OUC has adopted a Statistically Adjusted Engineering ("SAE") modeling technique developed by Itron. This approach entails specifying end-use variables (xHeat for heating, xCool for cooling, and xOther for other use) and utilizing these variables in multi-regression models to forecast sales. SAE variables allow anticipated shifts in customer end-use consumption driven by the type, saturation and efficiency of heating and cooling equipment, and other end-use devices to be represented along with econometric drivers and the effects of photovoltaic systems ("PV") and electric vehicles ("EV") in the forecast models. Itron reviews OUC's application of these techniques and provides data on heating, cooling, and other end-use load trends. These techniques are used to develop the forecasts for both the OUC and St. Cloud service territories.

4.1.1 Residential

The residential sales forecast consists of both a customer forecast model and an average use per customer model. Monthly average usage models were estimated using actual data for the period 2011 to 2024. This provides 14 years of historical data and enough observations to estimate strong regression models. Once models showing the number of expected customers and the expected average use per customer are developed, the projected residential sales by year (y) and month (m) are calculated as the product of the customer and average usage forecasts:

$$Sales_{y,m} = Customers_{y,m} \times Average\ Usage_{y,m}$$

4.1.1.1 Residential Customer Forecast

Residential customers are forecast as a function of household growth for Orange County for the OUC service territory and Osceola County for the St. Cloud service territory. There is a strong correlation between historical changes in customer counts and historical changes in households. The multi-regression model for residential customers is represented as:

$$Customers_{y,m} = \beta_0 + \beta_1(Households_{y,m})$$

The coefficients (β) are outputs of the multi-regression models.

4.1.1.2 Average Use Forecast

The residential forecast models utilize multi-regression modeling made up of three major components:

1. Changes in the economy, such as median household income and household size.
2. End-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements.
3. Weather variables, which serve to allocate the seasonal impacts of weather throughout the year.

The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment ($xHeat_{y,m}$), cooling equipment ($xCool_{y,m}$), and other equipment ($xOther_{y,m}$). The xHeat, xCool and xOther variables are defined as a product of an annual equipment index and a monthly usage multiplier. This model is represented as:

$$Average\ Usage_{y,m} = \beta_1(xHeat_{y,m}) + \beta_2(xCool_{y,m}) + \beta_3(xOther_{y,m})$$

Where:

$xHeat_{y,m}$ = $Economics_{y,m}$ x $HeatingEquipment_{y,m}$ x $HDD_Index_{y,m}$

$xCool_{y,m}$ = $Economics_{y,m}$ x $CoolingEquipment_{y,m}$ x $CDD_Index_{y,m}$

$xOther_{y,m}$ = $Economics_{y,m}$ x $OtherEquipment_{y,m}$

A customer's monthly usage level is impacted by several economic factors, including household size and household income in real dollars.

$$Economics_{y,m} = \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\ y,m}}\right)^{0.542} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\ y,m}}\right)^{0.130}$$

The annual equipment variables (HeatEquip, CoolEquip, OtherEquip) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels.

$$HeatEquip_y = \sum_{tech} Weight \times \left(\frac{Saturation_y / Efficieny_y}{Saturation_{base\ y} / Efficieny_{base\ y}}\right)$$

$$CoolEquip_y = \sum_{tech} Weight \times \left(\frac{Saturation_y / Efficieny_y}{Saturation_{base\ y} / Efficieny_{base\ y}}\right)$$

$$OtherEquip_y = \sum_{tech} Weight \times \left(\frac{Saturation_y / Efficieny_y}{Saturation_{base\ y} / Efficieny_{base\ y}}\right)$$

The following degree day index variables serve to allocate the seasonal impacts of weather throughout the year. For historic periods, actual heating degree days ("HDD") and cooling degree days ("CDD") are used. Normal HDDs and CDDs are used for forecast periods.

$$HDD_Index_{y,m} = \frac{HDD_{y,m}}{Normal\ HDD_y}$$

$$CDD_Index_{y,m} = \frac{CDD_{y,m}}{Normal\ CDD_y}$$

4.1.2 Non-Residential

4.1.2.1 General Service Non-Demand ("GSND")

The General Service Non-Demand ("GSND") and General Service Demand Secondary ("GSD Secondary") classes are modeled as a combined General Service Secondary class ("GS Secondary") because the historic data indicates customer migration has occurred back and forth between the two classes. The result is a single model, which produces predicted values with a higher correlation than that of two separate models. The forecast is later split between GSND and GSD Secondary using the monthly relationships between the two classes in the most recent year of actual data.

The framework for the GS secondary class sales forecast is similar to the residential class sales forecast except modeled on a total sales basis instead of by average use. It also has three major components and utilizes the SAE model framework. The end-use equipment variables are based on commercial appliance and equipment saturation and efficiency projections. The economic driver in the model is Orlando Standard Metropolitan Statistical Area ("SMSA") Gross Metro Product in real dollars. The third component is the weather variable, which is entirely composed of CDDs. HDDs are not used in the GS Secondary model because no statistically valid correlation between HDDs and sales could be identified. The xCool and xOther variables used in the GS secondary forecast use the same methodology as the residential forecast but with different economic assumptions.

The GS Secondary sales model is represented as:

$$Sales_{y,m} = \beta_1(xCool_{y,m}) + \beta_2(xOther_{y,m})$$

GS secondary customers are forecast as a function of population for Orange County for the OUC service territory and Osceola County for the St. Cloud service territory. There is a strong correlation between historical changes in customer counts and historical changes in the Orange County population. St. Cloud historical customers also correlate well with the Osceola County population.

The GS Secondary customer model is represented as:

$$Customers_{y,m} = \beta_0 + \beta_1(Population_{y,m})$$

4.1.2.2 General Service Demand ("GSD")

Forecast sales to GSD Secondary customers were modeled as discussed above. In addition to the customers taking service at secondary voltage, OUC serves 27 customers (excluding 6 OUC water plants) at primary voltage. These primary customers are forecasted as a whole on a total sales basis similar to the GSD secondary forecast.

Sales from the various GSD models are totaled to complete the GSD forecast.

4.1.2.3 Streetlights

Private and public lighting consumption is forecast separately. Both classes are not impacted by the weather, and the SAE modeling approach does not apply. Therefore, simple regression models are used to generate both forecasts. The forecast for private streetlights includes a linear trend to capture the historic organic growth that is expected to continue within the forecast period. The forecast for public streetlights does not include a linear trend as any growth in the number of lights has been offset by the replacement of traditional HPS and MH fixtures with LED fixtures.

4.1.2.4 OUC Use

OUC Use sales are those to OUC Water Plants, OUCooling Plants, and OUC facilities. The OUC Use models utilize CDDs, but not HDDs or the factors included in the "Other" SAE modeling variable.

4.1.3 Net Energy for Load ("NEL") and Peak Demand Forecast

The individual OUC and St. Cloud net energy for load forecasts are generated based on the respective sales forecasts described above and the historic relationship between actual monthly sales and NEL. Peak demand forecasts are then developed for each system based on the forecast NEL and the historic relationship between NEL, peak demand and daily weather.

4.2 Base-Case Forecast Assumptions

Incorporated into the forecast regression models are sets of underlying economic, demographic, and weather assumptions.

4.2.1 Economics & Demographics

The economic and demographic assumptions are derived from forecasts for Orange County, Osceola County, and the Orlando SMSA provided by S&P Global.

4.2.1.1 Median Household Income

The residential sales forecast models use Median Household Income in real dollars, as shown in Table 4-1.

4.2.1.2 Gross Metro Product

The commercial average usage forecast models use Gross Metro Product in real dollars, as shown in Table 4-1.

4.2.1.3 Households and Population

The residential and commercial customer forecast models use households and population, respectively. The primary demographic drivers in the residential average usage forecast models are the number of households and the population (see Table 4-1). The population data is divided by the household data to determine household size used in the residential average usage forecast models.

Table 4-1 Economic & Demographic Projections

Year	Orlando SMSA Median Household Income[1]	Orlando SMSA Gross Metro Product ($ Billions)[2]	Orange County (Thousands)		Osceola County (Thousands)	
			Households	Population	Households	Population
2026	$58,247	$197.1	616.2	1,559.5	185.3	497.7
2031	$60,520	$223.3	655.2	1,635.0	212.9	566.1
2035	$62,287	$247.5	693.1	1,715.2	235.3	622.6
Average Annual Increase						
26 - 31	0.8%	2.5%	1.2%	1.0%	2.8%	2.6%
26 - 35	0.7%	2.6%	1.3%	1.1%	2.7%	2.5%
(1) 2009 dollars (2) 2017 dollars						

4.2.3 Weather

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly CDDs are used to capture electric cooling load requirements while HDDs are used to capture electric heating load requirements. CDDs and HDDs are calculated from the daily average temperatures as reported by the National Weather Service for the weather station at the Orlando International Airport. CDDs are calculated using a 65°F base temperature as follows:

$$CDD_d = (Avg\ Temp_d - 65°F)\ when\ Avg\ Temp_d \geq 65°F$$

The daily CDD values are then aggregated to yield monthly CDDs for each year as follows:

$$CDD_{y,m} = \sum CDD_{y,m,d}$$

Daily HDD values are calculated in a similar manner using a base temperature of 65°F as follows:

$$HDD_d = (65°F - Avg\ Temp_d)\ when\ Avg\ Temp_d \leq 65°F$$

The daily HDD values are then aggregated to yield monthly HDDs for each year as follows:

$$HDD_{y,m} = \sum HDD_{y,m,d}$$

Due to historic weather trending warmer that escalation was continued to the forecast period in order to come up with "Normal" monthly weather with CDDs increasing and HDD decreasing annually over the forecast period.

4.3 Base-Case Load Forecast

A long-term annual base-case forecast was developed using the methodology and assumptions outlined above.

4.3.1 Customer and Sales Forecast Results

Total customers and retail sales for OUC and St. Cloud are expected to increase as shown in Table 4-2 through Table 4-5.

4.3.1.1 Residential Forecast

Increasing average usage per residential customer due to electric vehicle adoption is projected to be mitigated by increased appliance efficiency, increased customer conservation, increased penetration of rooftop solar, and declining household size, resulting in an increase in average usage per residential customer over the forecast period 2026 through 2035. Residential sales are projected to grow for OUC at an average annual rate of 2.8 percent and 4.4 percent in St. Cloud over this same period. The number of residential customers is projected to grow at an average annual rate of 1.4percent for OUC and 3.7percent for St. Cloud over this same period.

4.3.1.2 GSND Forecast

GSND is comprised of small commercial customers. GSND sales are projected to grow at an average annual rate of 1.2 percent and 2.0percent for OUC and St. Cloud, respectively, between 2026 and 2035. The number of GSND customers is projected to grow at an average annual rate of 0.5 percent and 2.3 percent, respectively, for OUC and St. Cloud over this same period.

4.3.1.3 GSD Forecast

GSD is comprised of large commercial and industrial customers. Sales are projected to grow at an average annual rate of 1.6 percent and 2.1 percent for OUC and St. Cloud, respectively, between 2026 and 2035. The number of GSD customers is projected to grow at an average annual rate of 0.5 percent and 2.3 percent, respectively, for OUC and St. Cloud over this same period.

Table 4-2 OUC Long-Term Sales Forecast (GWh)

Year	Residential	GSND	GSD	Lighting	OUC Use	Total Retail
2026	2,276	453	3,518	59	172	6,478
2031	2,616	478	3,842	61	173	7,170
2035	2,923	506	4,051	62	173	7,715
Average Annual Increase						
26 - 31	2.8%	1.1%	1.8%	0.7%	0.1%	2.1%
26 - 35	2.8%	1.2%	1.6%	0.6%	0.1%	2.0%

Table 4-3 OUC Average Number of Customers Forecast

Year	Residential	GSND	GSD	Total Retail
2026	202,662	24,561	4,725	231,948
2031	217,053	25,339	4,873	247,265
2035	228,901	25,792	4,960	259,653
Average Annual Increase				
26 - 31	1.4%	0.6%	0.6%	1.3%
26 - 35	1.4%	0.5%	0.5%	1.3%

Table 4-4 St. Cloud Long-Term Sales Forecast (GWh)

Year	Residential	GSND	GSD	Lighting	Total Retail
2026	806	71	171	3	1,051
2031	1,015	78	190	3	1,286
2035	1,190	85	206	3	1,484
Average Annual Increase					
26 - 31	4.7%	1.9%	2.1%	0.0%	4.1%
26 - 35	4.4%	2.0%	2.1%	0.0%	3.9%

Table 4-5 St. Cloud Average Number of Customers Forecast

Year	Residential	GSND	GSD	Total Retail
2026	57,488	4,564	390	62,442
2031	70,273	5,109	437	75,819
2035	79,804	5,582	478	85,864
Average Annual Increase				
26 - 31	4.1%	2.3%	2.3%	4.0%
26 - 35	3.7%	2.3%	2.3%	3.6%

4.3.2 Forecast Hourly Peak Demand and NEL

Peak demand growth is driven by the aggregate retail load forecasts for OUC and St. Cloud. Seasonal hourly peaks and annual NEL are presented for OUC and St. Cloud in Tables 4-6 and 4-7, respectively. Table 4-8 represents the combined seasonal coincident hourly peak demand and NEL forecasts for OUC and St. Cloud.

Table 4-6 OUC Forecast Hourly Peak Demand (Summer and Winter) and NEL

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	1,272	1,007	6,568
2031	1,322	1,117	7,270
2035	1,395	1,178	7,823
Average Annual Increase			
26 - 31	0.8%	2.1%	2.0%
26 - 35	1.0%	1.8%	2.0%

Table 4-7 St. Cloud Forecast Hourly Peak Demand (Summer and Winter) and NEL

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	296	224	1,227
2031	341	275	1,501
2035	388	313	1,733
Average Annual Increase			
26 - 31	2.9%	4.2%	4.1%
26 - 35	3.0%	3.8%	3.9%

Table 4-8 System Forecast Coincident Hourly Peak Demand (Summer and Winter) and NEL (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	NEL (GWh)
2026	1,565	1,162	7,795
2031	1,659	1,299	8,770
2035	1,776	1,420	9,556
Average Annual Increase			
26 - 31	1.2%	2.2%	2.4%
26 - 35	1.4%	2.3%	2.3%

4.4 High and Low Load Scenarios

In addition to the base-case, two long-term forecast scenarios representing a high and low range around the forecast peak demand and NEL were constructed to test for sensitivity of uncertain economic conditions and

customer growth. Weather conditions deviating from normal were not included in sensitivity testing due to non-growth-related impacts and an equal probability of affecting any given year either negatively or positively. The high and low load scenarios represent alternatives to the base-case forecast and are defined by 0.5 percent higher and 0.5 percent lower economic growth rates, respectively. Table 4-9 represents a summary of the high and low load scenarios.

Table 4-9 High and Low Scenario System Forecast Peak Demand (Summer and Winter) and NEL (Total of OUC and St. Cloud)

High Load Scenario			
Year	Summer	Winter	NEL
	(MW)	(MW)	(GWh)
2026	1,567	1,162	7,801
2031	1,672	1,307	8,837
2035	1,802	1,438	9,683
Average Annual Increase			
26 - 31	1.3%	2.4%	2.5%
26 - 35	1.6%	2.4%	2.4%
Low Load Scenario			
Year	Summer	Winter	NEL
	(MW)	(MW)	(GWh)
2026	1,564	1,162	7,789
2031	1,645	1,290	8,705
2035	1,751	1,403	9,432
Average Annual Increase			
26 - 31	1.0%	2.1%	2.2%
26 - 35	1.3%	2.1%	2.1%

5.0 DEMAND-SIDE MANAGEMENT

Sections 366.80 through 366.83, and 403.519, Florida Statutes ("F.S."), are known collectively as the Florida Energy Efficiency and Conservation Act ("FEECA"). Section 366.82(2), F.S., requires the Florida Public Service Commission ("PSC") to adopt appropriate goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. Pursuant to Section 366.82(6), F.S., the PSC must review the conservation goals of each utility subject to FEECA at least every five years. The six utilities subject to FEECA are Florida Power & Light Company ("FPL"), Duke Energy Florida, LLC. ("DEF"), Tampa Electric Company ("TECO"), Florida Public Utilities Company ("FPUC"), OUC, and JEA (referred to collectively as the "FEECA utilities").

OUC's residential and commercial/industrial numeric conservation goals for the 2025 through 2029 period were established by the PSC pursuant to Order No. PSC-2024-0433-FOF-EG issued September 20, 2024, as amended by Order No. PSC-2024-0433A-FOF-EG issued September 24, 2024. These PSC-established annual demand-side management ("DSM") goals are presented in Tables 5-1 and 5-2.

OUC committed to a 1 percent goal of energy efficiency as a percent of retail sales. This includes measures beyond those measured through FEECA. Because OUC must operationally plan to generate enough energy to meet demand at all times, and because OUC can incentivize, but not control, actual adoption, this forecast is being used for purposes of this Ten-Year Site Plan.

Table 5-1 Residential DSM Goals Approved by the PSC

Calendar Year	Summer (MW)	Winter (MW)	Annual (GWh)
2025	0.111	0.181	1.072
2026	0.113	0.192	1.129
2027	0.114	0.203	1.186
2028	0.116	0.214	1.243
2029	0.118	0.225	1.301

Table 5-2 Commercial/Industrial DSM Goals Approved by the PSC

Calendar Year	Summer (MW)	Winter (MW)	Annual (GWh)
2025	0.485	0.380	3.207
2026	0.534	0.411	3.508
2027	0.577	0.438	3.769
2028	0.620	0.463	4.019
2029	0.661	0.485	4.247

OUC has continued to promote its DSM and conservation programs to increase customer awareness of such programs. Not only do these programs help customers save money by saving energy, but the programs also help OUC reduce emissions of carbon dioxide (CO_2) and better position OUC to meet possible future greenhouse gas regulations. It should be noted that government mandates have forced manufacturers to increase their efficiency standards of appliances, thereby decreasing the incremental amount of cost-effective energy savings achievable, and the efficiency of new power generation equipment has increased. Appliance and generating unit efficiency improvements have muted the effectiveness of DSM and conservation programs, as overall efficiency increases in the marketplace partially offset the benefit of such programs.

The conservation programs included in OUC's 2025 DSM Plan (approved by the PSC on April 15, 2025) and offered to OUC's customers in 2025 consist of the following:

- Residential Existing Home Rebates Program
- Residential Efficiency Delivered Program
- Residential New Home Rebates Program
- Commercial/Industrial Prescriptive Rebates Program
- Commercial/Industrial Lighting Rebates Program
- Commercial/Industrial Custom Incentives Rebates Program

The remainder of this section describes OUC,s residential home energy surveys and commercial/industrial energy audits (Section 5.1), and each of the DSM and conservation programs outlined above (Sections 5.2 and 5.3). Incentives and rebate amounts included in the program descriptions are current as of the time this report was prepared. In addition to offering these programs, OUC continues to play an active role in promoting conservation through community relations as discussed in Section 2.4 and Section 3.6 of this Ten-Year Site Plan.

5.1 Energy Survey Programs[9]

5.1.1 Residential Home Energy Survey Program

OUC has been offering home energy surveys dating back to the 1980's. The home energy walk-through surveys are designed to provide residential customers with recommended energy efficiency measures and practices that customers can implement and to encourage participation in various OUC rebate programs. The home energy surveys are available to both single family and multi-family residential customers.

The Residential Energy Walk-Through Survey includes a review of the customer's electric consumption history as well as a walk-through review of the attic; heating, ventilation, and air conditioning (HVAC) system; air duct and air returns; window caulking; weatherstripping around doors; and, if applicable faucets, toilets and lawn sprinkler systems. OUC provides participating customers specific tips on conserving electricity and water as well as details on customer rebate programs. OUC Conservation

[9] As noted in OUC's 2025 DSM Plan, discussion of OUC's Residential Home Energy Survey and Commercial/Industrial Energy Audit programs is included for informational purposes as OUC has continued to offer the programs. Demand and energy reductions associated with these programs are not treated as contributing to the numeric conservation goals established by the FPSC for OUC.

Specialists use this walk-through type of audit technique as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

One of the primary benefits of the Residential Energy Survey Program is the education it offers customers on energy conservation measures and the ways lifestyle and behavior can directly affect energy use. Customers participating in the Energy Survey Program are provided with historical energy usage and a list of relevant recommended conservation measures for implementation. Customers receive an analysis report that includes pro forma estimates of implementation costs, savings, and payback periods for recommended measures. Customers benefit from the increased comfort experienced and decreased electric and water bills when efficiency measures are implemented.

The Home Energy Survey rates a customer's home energy use efficiency and where improvements can yield lower utility bills. To participate, OUC customers may request an appointment for a Walk-Through Energy Survey by calling the OUC Customer Service Call Center. Participation is tracked through service orders that are produced when appointments are scheduled and completed.

5.1.2 Commercial/Industrial Energy Audit Program

OUC's Commercial/Industrial Energy Audit Program has been offered for several years. These audits are focused on increasing the energy efficiency and energy conservation of commercial buildings. Each audit includes a free survey comprised of a physical walk-through inspection of the commercial facility performed by trained and experienced energy experts. The survey examines heating and air conditioning systems including duct work, refrigeration equipment, lighting, water heating, motors, process equipment, and the thermal characteristics of the building including insulation. Following the inspection, the customer receives a written report detailing cost-effective recommendations to improve the energy and water efficiency of the building. Participating customers are encouraged to consider other recommended OUC commercial programs and directly benefit from energy conservation measures, which decrease their electric and water bills.

OUC customers may participate by calling the OUC Customer Service Call Center or contacting their assigned key account manager and requesting an appointment for a Walk-Through Energy Survey. Participation is tracked through service orders that are produced when appointments are scheduled and completed.

5.2 Residential Programs

5.2.1 Residential Existing Home Rebates Program

OUC's Residential Existing Home Rebate Program provides rebates for the following six measures:

- Heat Pump Water Heater Rebates
- Heat Pump A/C Rebates
- Ceiling Insulation Rebates
- Duct Repair Rebates
- ENERGY STAR® Windows Rebates
- Smart Thermostat Rebates

These six measures are common to all three of OUC's Residential DSM program; all measures except the Smart Thermostat Rebates measure, which is slated to be released in 2026, are measures that OUC has been offering through its 2020 DSM Plan and earlier DSM program offerings. Customers may participate by submitting a rebate application online at http://www.OUC.com/rebates or via email, mail, in-person, or facsimile. Proof of purchase and/or receipts are required to be included in the application and repairs can be carried out by a contractor or the customer. Participation is tracked based on the number of rebates processed. Typically, these rebates are credited on the customer's bill, or a check can be processed and sent to the customer or the property owner who may have paid for the improvement.

Heat Pump Water Heater Rebate Measures

Commonly referred to as hybrid electric heat pump water heaters, heat pump water heaters with a Uniform Energy Factor (UEF) in excess of 2.2 can cut water heating electric use and costs by more than half. Across all three of OUC's Residential DSM Programs, OUC currently offers a rebate of $500 for heat pump water heaters; this rebate amount may be adjusted in the future at OUC's discretion.

Heat Pump A/C Rebate Measures

Across all three of OUC's Residential DSM Programs, OUC offers separate rebate amounts for the following two Air Source Heat Pump measures: CEE Tier 2 and ENERGY STAR®/CEE Tier 1. This measure provides rebates to qualifying customers in existing or new homes who install heat pumps having a seasonal energy efficiency ratio (SEER2) of 15.2 or higher, along with a Heating Season Performance Factor of greater than 9.0. Customers receive a rebate in the form of a credit on their bill ranging up to $1,150, depending upon the SEER or SEER2 rating and capacity (tons) of the new heat pump. The following table illustrates the rebate values available depending on the size and efficiency of the Heat Pump installed; these rebate amounts may be adjusted in the future at OUC's discretion.

	SEER2 Upgraded To:							
	SEER2	15.2 - 15.99	16.0 - 16.99	17.0 - 17.99	18.0 - 18.99	19.0 - 19.99	20.0 - 20.99	21.0 - 21.99	22.0 - 22.99
	SEER	16.00 - 16.99	17.0 - 17.99	18.0 - 18.99	19.0 - 19.99	20.0 - 20.99	21.0 - 21.99	22.0 - 22.99	23.0 - 23.99
AC Size (Tons)	1	-	-	$55	$85	$115	$140	$165	$185
	1.5	-	$55	$110	$155	$200	$240	$275	$305
	2	-	$90	$165	$230	$285	$340	$385	$425
	2.5	$45	$130	$220	$300	$370	$435	$495	$550
	3	$65	$165	$275	$370	$455	$535	$605	$670
	3.5	$90	$200	$330	$440	$540	$635	$715	$790
	4	$110	$235	$385	$510	$625	$730	$825	$910
	5	$150	$310	$490	$655	$795	$925	$1,045	$1,150
SEER2 is the main rating that determines the rebate value.									
If only SEER listed on AHRI, use corresponding SEER column above.									

Ceiling Insulation Rebate Measures

The attic is often the easiest place to add insulation and lower total energy consumption throughout the seasons. OUC has previously offered Ceiling Insulation rebates as a separate program, but as with other measures, in OUC's 2025 DSM Plan, ceiling insulation rebates are now offered as a qualified measure across all three of OUC's Residential DSM Programs. OUC's Ceiling Insulation measure is designed to encourage customers to upgrade their attic insulation to save energy and reduce OUC's peak demand and to save

customers money by reducing their electric bills. Participating customers receive a rebate of $0.12 per square foot for upgrading their attic insulation to R-38 or higher; the rebate amount may be adjusted in the future at OUC's discretion. The rebate is available for insulation added to conditioned areas only.

Duct Repair Rebate Measures

Beginning in 2000, OUC offered a Duct Repair Rebates Program designed to encourage customers to repair leaking ducts on existing systems. In OUC's 2025 DSM Plan, duct repair is offered as a qualified measure across all three of OUC's Residential DSM Programs. Ducts must be sealed with mastic and fabric tape or any other Underwriters Laboratory (UL) approved duct tape. Participating customers receive a rebate for 100 percent of the cost of duct repairs on their homes, up to $100; the rebate amount may be adjusted in the future at OUC's discretion.

ENERGY STAR® Windows Rebate Measures

Installation of energy-efficient windows can help reduce energy consumption of heating, cooling, and lighting, thereby reducing utility generation capacity and saving customers money on their power bills. OUC has historically offered rebates to support efficient window installations through its High-Performance Windows Rebates program; beginning with OUC's 2025 DSM Plan, this offering has been converted to a measure that is available in all three of OUC's Residential DSM Programs and this measure has been modified to offer rebates only for windows that meet ENERGY STAR® criteria consisting of National Fenestration Rating Council (NFRC) certification, meets ENERGY STAR® southern regionally accepted standards of a U-Factor ≤ 0.32 and a Solar Heat Gain Coefficient (SHGC) ≤ 0.23. Participating customers receive a rebate of $1.50 per square foot for the purchase of ENERGY STAR® rated energy efficient windows; the rebate amount may be adjusted in the future at OUC's discretion.

Smart Thermostat Rebate Measures

The only new residential DSM measure submitted in OUC's 2025 DSM Plan is the Smart Thermostat Rebate Measure. A Smart Thermostat is like a programmable thermostat, but the Smart Thermostat utilizes internet connectivity to allow the customer or their designated surrogates to more actively control the home's heating, cooling, and ventilation system behavior. The benefits of Smart Thermostats include more precise control of comfort, automated control of conditioned space based on actual occupancy, schedule and environmental conditions and the ability to permit remote access to the thermostat to pre-condition a space – all of which assist customers by saving money on their bills and reducing need for utility generation capacity. OUC's Smart Thermostat measure provides a rebate amount of $50 per installation; the rebate amount may be adjusted in the future at OUC's discretion.

5.2.2 Residential Energy Efficiency Delivered Program

What was originally referred to as the 'home energy fix-up program' was subsequently revamped and expanded to allow for any OUC customer (energy, water, or both energy and water) to participate and renamed the 'Efficiency Delivered' program. By 2020, the program was expanded to allow for participation by all residential customers regardless of home type (single family and multi-family) and regardless of ownership status (owned or rented with landlord approval).

OUC's Residential Efficiency Delivered Program is available to residential customers and provides support for up to $2,500 of energy and water efficiency upgrades based on the assessed needs of the customer's home and the customer's household income. OUC determines its contribution toward the cost of

improvements utilizing three household income tiers:

Household Income	OUC Contribution
Less than $40,000	85% of the actual cost of repairs and upgrades
$40,001–$60,000	50% of the actual cost of repairs and upgrades
Greater than $60,000	Rebates only

1. $40,000 or less: OUC contributes 85 percent of total cost, not exceeding $2,125
2. $40,001 to $60,000: OUC contributes 50 percent of the total cost, not exceeding $1,250 and
3. greater than $60,000: OUC will contribute the value of the current rebate incentives that apply toward the measures employed.

To participate in the Residential Efficiency Delivered Program, a customer must request and complete a no-charge Residential Home Energy Survey. A Conservation Specialist from OUC performs a survey at the customer's home and determines which home improvements have the potential to save the customer the most money. Ordinarily, Energy Survey recommendations require a customer to spend money replacing aging equipment or adding energy conservation measures: however, customers may not have discretionary income to implement these measures - especially those customers with lower household incomes. To be eligible for this program, the customer's account must be in good credit standing, with the exception that low-income customers can participate if they have a current balance that is not delinquent. Under this program, OUC arranges for a licensed, approved contractor to perform the necessary repairs based on OUC negotiated and contracted rates. The remaining portion of the cost for which the customer is responsible (i.e., the 15 or 50 percent customer share depending on household income), is paid directly to OUC or recovered interest-free over a 24-month period on the participant's monthly electric bill.

The purpose of the Residential Efficiency Delivered Program is to achieve utility energy and water conservation goals and to reduce customers' energy and water costs, especially for low-income households. Implementation of measures offered through the Efficiency Delivered program helps to dampen the impact of seasonal billing changes due to weather variation for customers for which a larger portion of household income is required to pay the utility bill. Through this program, OUC helps customers achieve lower utility bills, while providing the additional benefit of decreasing the likelihood of incurring costly service disconnect fees and late charges resulting from an inability to pay the utility bill. OUC believes that this program particularly helps low-income customers better afford other essential living expenses. For all participating customers, this program offers a single point of contact to facilitate the implementation of a whole suite of conservation measures leveraging OUC's purchasing power to receive reasonable costs with installation offered by pre-screened qualified contractors.

OUC's Residential Efficiency Delivered Program includes each of the measures included in OUC's Residential Existing Home Rebates Program (please refer to Section 5.2.1 herein for descriptions of those measures), as well as measures related to air sealing infiltration control (i.e., attic stair cover insulation, door sweeps and caulking and weatherstripping) and heating and cooling system maintenance (i.e., maintenance checks and air filter replacements).

5.2.3 Residential New Home Rebates Program

OUC's Residential New Home Rebates Program provides a flexible "a la carte" program through which a home buyer can select a limited number of measures available through OUC's Residential Existing Home Rebates Program (including Heat Pump Water Heaters, Heat Pump Air Conditioners, Solar Thermal Water Heaters, and a collection of water conservation devices). This program structure has evolved from earlier DSM program offerings based on feedback from the residential building community and OUC's efforts to streamline the marketing and administration of all its residential DSM programs and measure offerings. This program encourages builders to build structures and install equipment above current building code to maximize energy savings achievable.

5.3 Commercial/Industrial Programs

5.3.1 Commercial/Industrial Prescriptive Rebates Program

OUC's Commercial/Industrial Prescriptive Rebates Program consists of the following measures:

- Ceiling Insulation Rebates
- Duct Sealing Rebates
- ENERGY STAR® Windows Rebates
- Heat Pump Water Heater Rebates
- LED Lighting and Occupancy Sensors Rebates
- Reflective Roof Treatment (including Cool Roof) Rebates
- Smart Thermostat Rebates
- Solar Thermal Water Heating Rebates
- Window Shade Film Rebates

All measures except the Smart Thermostat Rebates measure, which is new to the current DSM Plan, are measures that OUC included in its 2020 DSM Plan and earlier DSM program offerings. Commercial and industrial customers in good standing may participate in the Commercial/Industrial Prescriptive Rebates Program. Customers can initiate participation in this program in any combination of measures they choose by calling a customer service representative at OUC or by submitting an application online at http://www.OUC.com/rebates to take advantage of any of the measures offered through the Program. As applicable to specific measures, proof of purchase and/or receipts are required to be included in the application, and repairs or installation of qualifying equipment can be performed by a contractor or by the customer. Participation is tracked based on the number of rebates processed; typically, these rebates are credited to the customer's bill, or a check can be processed and sent to the business owner or landlord who may have paid for the improvements associated with measures selected by the customer.

Ceiling Insulation Rebate Measures

OUC offers Ceiling Insulation rebates to enable customers to increase their facility's resistance to heat loss and gain, which saves energy and reduces system peak demand and saves customers money by reducing their electric bills. Participating customers receive a rebate of $0.12 per square foot for upgrading their ceiling insulation to R-38 or higher; the rebate amount may be adjusted in the future at OUC's discretion. The rebate is available for insulation added to conditioned areas only.

Duct Sealing Rebate Measures

This measure is designed to encourage customers to repair and maintain the ductwork on existing HVAC systems to improve the overall efficiency of their HVAC systems. OUC will rebate 100 percent of costs, up to $100; the rebate amount may be adjusted in the future at OUC's discretion. Ducts must be sealed with mastic and fabric tape or other Underwriters Laboratory approved duct tape on all accessible boots, joints, and seams of the air duct system. Commercial and industrial customers with systems greater than 5.5 tons are eligible for rebates through OUC's Commercial/Industrial Custom Incentive Rebates Program. Invoices must include separately itemized amounts for each system repair and must reflect the repair or sealing method used.

ENERGY STAR® Windows Rebate Measures

Energy-efficient windows help minimize consumption by heating, cooling, and lighting, thereby reducing utility generation capacity and saving customers on their power bills. OUC has historically offered rebates to support efficient window installations through its High-Performance Windows Rebates program and as an eligible measure through its Commercial Custom Incentive Program; beginning with OUC's 2025 DSM Plan, this offering has been converted to a measure that is available to commercial and industrial customers through the Commercial/Industrial Prescriptive Rebates Program (and also through the Commercial Custom Program). This measure has been modified to provide rebates for windows that meet ENERGY STAR® criteria. Participating customers receive a rebate of $1.50 per square foot for the purchase of ENERGY STAR® rated energy efficient windows; the rebate amount may be adjusted in the future at OUC's discretion.

Heat Pump Water Heaters Rebate Measures

Commonly referred to as hybrid electric heat pump water heaters, heat pump water heaters with a coefficient of performance (COP) of greater than 2.0 can cut water heating electric use and costs by more than half. OUC offers the same rebates to commercial and industrial customers as it offers to residential customers who install heat pump water heaters. OUC currently offers a rebate of $500 for heat pump water heaters; this rebate amount may be adjusted in the future at OUC's discretion. Commercial and industrial customers who wish to install heat pump water heaters with greater capacity than residential units are eligible for rebates through OUC's Commercial/Industrial Custom Incentive Rebates Program.

LED Lighting and Occupancy Sensors Rebate Measures

Commercial and industrial customers that upgrade the efficiency of their lighting (i.e., LED lighting, occupancy sensors, and refrigerated display case LED lighting) may be eligible to receive a rebate of $250/kW through the lighting rebates measures that are available through OUC's Commercial/Industrial Prescriptive Rebates Program, Commercial/Industrial Lighting Rebates Program, and Commercial/Industrial Custom Incentive Rebates Program; this rebate amount may be adjusted in the future at OUC's discretion. Participation is open to facilities located within OUC's service area that receive electric service under an OUC commercial rate. Participants or customers may be any of the following:

- Individual customers who install more efficient lighting in their own facilities.
- National or local companies that install more efficient lighting.
- Local contractors, design/build firms, architectural and engineering firms, and commercial property developers working on behalf of OUC commercial customers.

Reflective Roof Treatment (Including Cool Roof) Rebate Measures

This measure is designed to reflect the sun's rays and lower roof surface temperature while increasing the lifespan of the roof. OUC will rebate customers at $0.12 per square foot for ENERGY STAR® cool/reflective roofing that has an initial solar reflectance greater than or equal to 0.70; this rebate amount may be adjusted in the future at OUC's discretion.

Smart Thermostat Rebate Measures

A Smart Thermostat is like a programmable thermostat, but the Smart Thermostat utilizes internet connectivity to allow the customer or their designated surrogates to more actively control the structure's heating, cooling, and ventilation system behavior. The benefits of Smart Thermostats include more precise control of comfort levels, automated control of conditioned space based on actual occupancy, schedule and environmental conditions and the ability to allow remote access to the thermostat to pre-condition a space – all of which assist customers by saving money on their bills and reduce need for utility generation capacity. OUC's Smart Thermostat measure provides a rebate amount of $50 per installation; the rebate amount may be adjusted in the future at OUC's discretion.

Solar Thermal Water Heating Rebate Measures

Solar water heating provides an efficient and carbon-neutral alternative to conventional water heating methods. OUC's Solar Thermal Water Heating Rebate measure provides rebate incentives to commercial and industrial customers who install this technology based on the volume (in kW) of conventional capacity avoided by the installation. The amount of the rebate is $900; this rebate amount may be adjusted in the future at OUC's discretion.

Window Shade Film Rebate Measures

Window shade film reduces the energy and demand cooling loads placed on OUC's electric system by heat gain in conditioned space. To reduce energy and peak demands, and to enable customers to reduce their electric bills, OUC offers a rebate of $0.55 per square foot of film installed in a customer's conditioned space; this rebate amount may be adjusted in the future at OUC's discretion.

5.3.2 Commercial/Industrial Lighting Rebates Program

Commercial and industrial customers that upgrade the efficiency of their lighting (i.e., LED lighting, occupancy sensors, and refrigerated display case LED lighting) may be eligible to receive a rebate of $250/kW through the lighting rebates measures that are available through OUC's Commercial/Industrial Prescriptive Rebates Program, Commercial/Industrial Lighting Rebates Program, and Commercial/Industrial Custom Incentive Rebates Program; this rebate amount may be adjusted in the future at OUC's discretion. Participation is open to facilities located within OUC's service area that receive electric service under an OUC commercial rate. Participants or customers may be any of the following:

- Individual customers who install more efficient lighting in their own facilities.
- National or local companies that install more efficient lighting.
- Local contractors, design/build firms, architectural and engineering firms, and commercial property developers working on behalf of OUC commercial customers.

5.3.3 Commercial/Industrial Custom Incentives Rebates Program

OUC has designed the Commercial/Industrial Custom Incentive Rebates Program to encourage electric demand reductions that go above and beyond the efficiency gains typically achieved in retrofit or replacement projects. Consequently, demand savings credit is based only on reductions that exceed current state and federal minimum efficiency standards, wherever such standards (e.g., Florida's Energy Efficient Building Code Standards) apply. In cases where these standards do not exist, savings credit is based on improvements relative to a customer's documented electric demand prior to participating in the program. The following measures are included in the Commercial/Industrial Custom Incentives Rebates Program; all of these are measures that OUC has been offering through its 2020 DSM Plan and earlier DSM program offerings:

- High Efficiency Packaged Terminal Air Conditioners Rebates
- High Efficiency Packaged Terminal Heat Pumps Rebates
- LED Lighting Rebates
- Occupancy Sensors Rebates
- Refrigerated Display Case LED Lighting Rebates
- Other Commercial Custom Incentive Measure Rebates

Through the Commercial/Industrial Custom Incentive Rebate Program, commercial and industrial customers receive incentives based on the demonstrated reduction in peak demand their projects achieve plus the value of the first-year energy savings. Energy and demand saving incentives are paid for the maximum one-hour average demand reduction that occurs during Summer Demand period defined as weekdays, between 1 p.m.– 6 p.m., from April through October. Pre- and post-installation inspections are required. Incentives and other program considerations are summarized below and may be changed in the future at OUC's discretion.

- $250 per kW reduction incentive for all lighting measures.
- $550 per kW reduction incentive plus $0.032 per kWh for all non-lighting measures.
- Incentives shall not exceed 50% of project cost.
- Incentives may be paid at 50% on project completion and remainder at one year depending on performance results.
- All incentives will be paid as a credit appearing on the customer's OUC statement.
- Simple return on investment must be greater than 2 years.
- Energy and demand conservation measures should have a useful life of at least 10 years.
- A maximum incentive of $200,000 per customer annually; this amount was increased from $100,000 by OUC in August 2025.

The following requirements must be met prior to work beginning:

1. Customer prepares and submits a Project Application. Customer downloads the application at: https://WWW.OUC.COM/SAVEYOURWAY
2. Customer schedules on-site inspection(s) and meeting(s) with OUC to review proposed project.
3. Customer works with OUC through the incentive funding commitment and approval process.
4. OUC provides customer project approval and incentive funding commitment.

5. Customer performs any required pre-installation Measurement and Verification (M&V).

After work is complete, the following must occur:
1. Customer submits Installation Report
2. Customer performs post-installation M&V
3. Customer documents the kW and kWh savings.
4. Customer schedules on-site inspection(s) by OUC to confirm installation and M&V results.
5. Customer obtains final approval from OUC and receives rebate in the form of a billing credit on OUC monthly statement.

In addition to the residential and commercial programs previously discussed, OUC continues to do more to reduce energy consumption through supply-side initiatives, including:

- Conservation Voltage Reduction (CVR) - The Conservation Voltage Reduction (CVR) Project is made possible by OUC's investment in its Advanced Meter Infrastructure (AMI) and more sophisticated distribution equipment. The availability of AMI customer load and voltage interval data provides an opportunity to optimize voltage control and thereby reduce energy consumption based on better awareness and monitoring of system conditions at customer service points. Benefits of CVR include conservation related reductions in customer energy usage and line losses (with associated reductions in fuel usage) and lower demands on generation resources. As of December 2025, OUC had 157 feeders of the total of 190 feeders under CVR control.
- OUC District Cooling's Chilled Water District(s) Efficiency Improvements – District Cooling currently serves over 200 customers and provides more than 61,000 tons of cooling. The value of District Cooling is attributed to more efficient and less costly generation and delivery of chilled water when compared to what a customer would likely produce independently. District Cooling invests in higher efficiency chillers and equipment and optimizes its operations on a continuous basis to provide a lower cost and more efficient solution for subscribing customers.

6.0 FORECAST OF FACILITIES REQUIREMENTS

6.1 Existing Capacity Resources

6.1.1 Existing Generating Capacity

OUC's total owned generating capability for OUC and St. Cloud (as of date this Ten-Year Site Plan was prepared) is 2,046 MW in the winter and 2,009 MW in the summer. OUC's existing generating capability (described in more detail in Section 2.0) consists of the following:

- Sole ownership of Stanton Energy Center Unit 1 (as of January 1, 2026)
- Joint ownership shares in Stanton Energy Center Unit 2 and Stanton A
- Sole ownership of Stanton Energy Center Unit B (Stanton B)
- Joint ownership shares of the Indian River combustion turbine units
- Joint ownership share of St. Lucie Unit 2 Nuclear Generating Facility
- Sole ownership of the Osceola Generating Station

St. Cloud's entitlement to capacity from Stanton Unit 2 is included as generating capability in Tables 6-2 and 6-3, consistent with the Interlocal Agreement described in Section 2.0.

6.1.2 Power Purchase Agreements

Corresponding to the construction of Stanton A, OUC entered into a PPA with SCF to purchase capacity from SCF's 65 percent ownership share of Stanton A. The original Stanton A PPA was for a term of 10 years and allowed OUC, KUA, and FMPA to purchase all of SCF's 65 percent capacity share. The utilities originally had options to extend the PPA beyond its initial term. OUC's Stanton A PPA has been extended through December 2031, and OUC has purchased an additional 87 MW from Stanton A through December 31, 2028. As discussed in Section 2, NextEra Energy has purchased SCF's interest in Stanton A.

As discussed in Section 2, OUC added 108.5 MWac of solar capacity (nameplate) in June 2020 through PPAs with NextEra, and added 149 MWac of solar capacity (nameplate) in December 2024, also through PPAs with NextEra. OUC also has PPAs associated with purchases of energy generated from landfill gas, as discussed in Section 2.

In 2020, OUC completed a comprehensive Electric Integrated Resource Plan ("EIRP") to guide OUC through the next 30 years[10]. Based on the results of the EIRP, OUC anticipates entering into PPAs for approximately 1,491 MWac of solar (nameplate) and 800 MWac of energy storage by the end of 2034 as summarized in Table 6-1.

[10] OUC anticipates refreshing its Electric integrated Resource Plan within the next 12 months.

Table 6-1 Anticipated Solar and Energy Storage PPAs

Commercial Operation Date	Nameplate Capacity (MWac) w/o Energy Storage	Energy Storage (MW)
June 2027	149	100
June 2029	149	0
June 2030	149	0
June 2031	149	100
June 2032	149	150
June 2033	373	250
June 2034	373	200

6.1.3 Power Sales Agreements

OUC's power sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland Electric are described in Section 2.3.

6.1.4 Retirements and Modifications of Generating Facilities

As mentioned previously, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026 and converting Stanton Unit 2 to be capable of operating only on natural gas by the end of 2027 (OUC is in the process of determining the final timing of the natural gas conversion). One factor affecting potential unit modifications and/or retirements is the impact of pending future environmental regulations. OUC will continue to monitor future environmental regulations that may impact its operating fleet and decisions related to generating units, and develop appropriate corresponding compliance plans.

6.2 Reserve Margin Requirements

The FPSC has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Florida Administrative Code for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criterion is generally consistent with practice throughout much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning criterion.

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast

Tables 6-2 and 6-3 (presented at the end of this section) display the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. OUC's capacity from renewable projects (discussed in Section 2.4) that is projected to be available at the time of peak demand is also reflected in Tables 6-2 and 6-3.

Table 6-2 and Table 6-3 indicate that OUC is projected to have adequate generating capacity to maintain the 15 percent reserve margin requirements through the period considered in this Ten-Year Site Plan (i.e.

through 2035). As such, this Ten-Year Site Plan does not include any further new capacity additions, beyond the solar and energy storage purchases associated with OUC's EIRP and discussed throughout this Ten-Year Site Plan.

6.3.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to its customers. OUC's current transmission system planning criteria are summarized in its annual filing to the Federal Energy Regulatory Commission. Please see OUC's FERC Form 715 for additional information.

Table 6-2 Projected Winter Reserve Requirements – Base-Case

	Retail and Wholesale Peak Demand (MW)[1]						Available Capacity (MW)					Reserves (MW)			Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin (MW)[7]
Year	OUC and STC	Mt. Dora	Chattahoochee	Lakeland	Winter Park	Total	Installed[2][8]	SEC A PPA	Landfill Gas	Solar[3]	Energy Storage[3]	Total[4]	Required[5]	Available[6]	
2025/26	1,231	20	7	50	17	1,325	1,889	437	19	0	0	2,345	185	1,020	836
2026/27	1,279	20	7	0	0	1,306	1,593	437	19	0	0	2,049	192	743	551
2027/28	1,322	20	0	0	0	1,342	1,593	437	19	0	100	2,149	198	807	609
2028/29	1,345	20	0	0	0	1,365	1,593	350	19	0	100	2,062	202	697	495
2029/30	1,368	21	0	0	0	1,389	1,593	350	19	0	100	2,062	205	673	468
2030/31	1,392	0	0	0	0	1,392	1,593	350	19	0	100	2,062	209	670	462
2031/32	1,416	0	0	0	0	1,416	1,593	0	19	0	200	1,812	212	396	183
2032/33	1,439	0	0	0	0	1,439	1,593	0	19	0	350	1,962	216	523	307
2033/34	1,464	0	0	0	0	1,464	1,593	0	19	0	600	2,212	220	749	529
2034/35	1,491	0	0	0	0	1,491	1,593	0	19	0	800	2,412	224	922	698

(1). Peak Demands shown are non-coincident.
(2). Includes existing net capability to serve OUC and St. Cloud.
(3). Capacity of Solar reflects capacity projected to be available at time of seasonal peak demand, which is assumed to be 0% for winter and 100% of nameplate capacity of energy storage.
(4). "Totals" may not add due to rounding.
(5). "Required Reserves" include 15 percent reserve margin on OUC and St. Cloud retail peak demand. OUC is not responsible for providing reserves to Mt. Dora, Chattahoochee, Lakeland, or Winter Park.
(6). "Available Reserves" equals the difference between total available capacity and total peak demand.
(7). Calculated as the difference between "Available Reserves" and "Required Reserves."
(8). Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period. Capacity from Stanton Energy Center Unit 1 no longer included beginning winter 2026/27 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

Table 6-3 Projected Summer Reserve Requirements – Base-Case

	Retail and Wholesale Peak Demand (MW)[1]						Available Capacity (MW)					Reserves (MW)			Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin (MW)[7]
Year	OUC and STC	Mt. Dora	Chattahoochee	Lakeland	Winter Park	Total	Installed[2][8]	SEC A PPA	Landfill Gas	Solar[3]	Energy Storage[3]	Total[4]	Required[5]	Available[6]	
2026	1,568	26	9	100	17	1,720	1,556	429	19	136	0	2,140	235	420	184
2027	1,614	26	9	0	0	1,649	1,556	429	19	210	100	2,314	242	665	423
2028	1,636	27	0	0	0	1,663	1,556	429	19	210	100	2,314	245	651	406
2029	1,613	27	0	0	0	1,640	1,556	342	19	285	100	2,302	242	662	420
2030	1,630	27	0	0	0	1,657	1,556	342	19	359	100	2,376	244	720	475
2031	1,664	0	0	0	0	1,664	1,556	342	19	434	200	2,551	250	887	638
2032	1,692	0	0	0	0	1,692	1,556	0	19	508	350	2,433	254	742	488
2033	1,721	0	0	0	0	1,721	1,556	0	19	695	600	2,870	258	1,149	890
2034	1,750	0	0	0	0	1,750	1,556	0	19	881	800	3,256	263	1,506	1,243
2035	1,783	0	0	0	0	1,783	1,556	0	19	881	800	3,256	267	1,474	1,206

(1). Peak Demands shown are non-coincident.
(2). Includes existing net capability to serve OUC and St. Cloud.
(3). Capacity of Solar reflects capacity projected to be available at time of seasonal peak demand, which is assumed to be 50% of nameplate capacity for summer solar without energy storage and 100% of nameplate capacity of energy storage.
(4). "Totals" may not add due to rounding.
(5). "Required Reserves" include 15 percent reserve margin on OUC and St. Cloud retail peak demand. OUC is not responsible for providing reserves to Bartow, Winter Park, Mt. Dora, Chattahoochee, or Lakeland. Wholesale sale shown to Lake Worth includes reserves.
(6). "Available Reserves" equals the difference between total available capacity and total peak demand.
(7). Calculated as the difference between "Available Reserves" and "Required Reserves."
(8). Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period. Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

7.0 SUPPLY-SIDE ALTERNATIVES

As discussed previously, consideration of OUC's current generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan). As such, no new capacity additions have been evaluated as part of this Ten-Year Site Plan, beyond the solar and energy storage purchases discussed throughout this Ten-Year Site Plan.

8.0 ECONOMIC EVALUATION CRITERIA AND METHODOLOGY

This section presents the economic evaluation criteria and methodology used for OUC's current planning processes.

8.1 Economic Parameters

The economic parameters are summarized below and are presented on an annual basis.

8.1.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.0 percent.

8.1.2 Present Worth Discount Rate

The present worth discount rate is assumed to be 7.5 percent.

8.2 Fuel Price Forecasts

The natural gas and fuel oil price forecasts reflected in this Ten-Year Site Plan were developed based on a combination of the NYMEX forward curve and projections provided by PIRA Energy Group ("PIRA"). PIRA was founded in 1976 and is an international energy consulting firm specializing in global energy market analysis and intelligence. Among other services, PIRA offers consulting on a broad range of subjects in the international crude oil, petroleum products, natural gas, electricity, coal, biofuels, and emissions markets. PIRA's clients include international and national integrated oil and gas companies, independent producers, refiners, marketers, oil and gas pipelines, electric and gas utilities, industrials, trading companies, financial institutions, and government agencies.

The coal forecast reflected in this Ten-Year Site Plan was developed based on projections by Energy Ventures Analysis, Inc. ("EVA") for use by OUC as well as recent offers from suppliers of Illinois Basin coal. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. In the energy area, much of EVA's work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas, and coal. EVA's clients in these areas include coal, oil, and natural gas producers; electric utility and industrial energy consumers; and gas pipelines and railroads. EVA also works for a number of public agencies, such as state regulatory commissions, the US EPA, and the US DOE, as well as interveners in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute, and the Center for Energy and Economic Development. EVA has provided testimony to numerous state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

9.0 ANALYSIS AND RESULTS

As discussed previously, consideration of OUC's existing generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

For informational purposes, OUC utilized PCI GenTrader to obtain the annual production costs associated for various load, fuel, and other sensitivity cases. GenTrader is a computer-based chronological production costing model developed for use in power supply system planning. GenTrader simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

The cumulative present worth cost ("CPWC") calculations presented in this section account for annual system costs (i.e. fuel and energy, non-fuel variable O&M, and startup costs) for each year of the expansion planning period and discounts each back to 2026 at the present worth discount rate of 7.5 percent. These annual present worth costs are then summed over the 10-year forecast period to calculate the total CPWC of the expansion plan being considered.

9.1 CPWC Analyses

9.1.1 Base-Case Analysis

The base-case considers the base load forecast presented in Section 4 and the base fuel price forecasts. The CPWC associated with the base-case analysis is approximately $2.640 billion.

9.1.2 Sensitivity Analyses

As part of its capacity planning process, OUC considers a number of sensitivity analyses to measure the impact of variations to critical assumptions. Among the numerous sensitivities that OUC may consider in its planning processes are high and low fuel prices, high and low load and energy growth projections, a case in which the differential between natural gas and coal price projections is held constant over time, and a high present worth discount rate case. Of these sensitivities, only the high load and energy growth projection sensitivity would potentially impact the timing of unit additions as compared to the base-case analysis. For informational purposes, the following subsections describe the high and low load and energy growth, the high and low fuel price, the constant differential fuel price, and the high present worth discount rate sensitivities.

9.1.2.1 High Load Forecast Sensitivity

The high load forecast is presented in Section 4.0; as with the base-case load forecast, OUC is anticipated to have sufficient capacity to maintain its 15 percent reserve margin under the high load forecast sensitivity. The CPWC associated with the high load analysis is approximately $2.660 billion.

9.1.2.2 Low-Load Forecast Sensitivity

The low-load forecast is presented in Section 4.0; as with the base-case load forecast, OUC is anticipated to have sufficient capacity to maintain its 15 percent reserve margin under the low load forecast sensitivity. The CPWC associated with the low-load analysis is approximately $2.620 billion.

9.1.2.3 High Fuel Price Forecast Sensitivity

OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis, this factor was not considered. The CPWC associated with the high natural gas and coal price forecast sensitivity is approximately $3.014 billion.

9.1.2.4 Low Fuel Price Forecast Sensitivity

OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis, this factor was not considered. The CPWC associated with the low natural gas and coal price forecast sensitivity is approximately $2.266 billion.

9.1.2.5 Constant Differential Natural Gas and Coal Price Forecast Sensitivity

The constant differential natural gas and coal price forecast sensitivity assumes that the differential in prices between coal and natural gas projected for 2026 will remain constant through 2035. The CPWC associated with the constant differential natural gas and coal price forecast sensitivity is approximately $2.647 billion.

9.1.2.6 High Present Worth Discount Rate Sensitivity

The high present worth discount rate sensitivity assumes a 10 percent present worth discount rate instead of the 7.5 percent present worth discount rate used in the other economic analyses discussed in this section. The CPWC associated with the high present worth discount rate sensitivity is approximately $2.393 billion.

10.0 ENVIRONMENTAL AND LAND USE INFORMATION

As discussed previously, consideration of OUC's current generating resources (including existing and planned PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

11.0 CONCLUSIONS

As discussed previously, consideration of OUC's current generating resources (including existing resources and anticipated PPAs) and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in this Ten-Year Site Plan).

In 2020, OUC completed a comprehensive Electric Integrated Resource Plan ("EIRP") to guide OUC through the next 30 years, and is in the process of refreshing the EIRP. OUC anticipates refreshing its Electric integrated Resource Plan within the next 12 months. Results of the 2020 EIRP have been discussed throughout this Ten-Year Site Plan. Relevant highlights of the 2020 EIRP and OUC's 2026 Ten-Year Site Plan include:

- OUC anticipates entering into PPAs for approximately 1,491 MWac of solar (nameplate) and 800 MW of energy storage by 2034.
- OUC anticipates placing the coal-fired Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026.
- OUC anticipates converting the coal-fired Stanton Energy Center Unit 2 to be capable of operating on 100 percent natural gas by the end of 2027.
- OUC has pledged to achieve Net Zero carbon emissions by 2050, with interim targets of 50% carbon emissions reductions by 2030 and 75% carbon emissions reductions by 2040, both as compared to 2005 levels.

12.0 TEN-YEAR SITE PLAN SCHEDULES

This section presents the schedules required by the Ten-Year Site Plan rules for the FPSC. The information contained within the FPSC Schedules is representative of the combined OUC and City of St. Cloud systems, consistent with all sections of the 2026 OUC Ten-Year Site Plan.

Schedule 1
Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.					
	Unit		Unit	Fuel		Fuel Transport		Fuel Days	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability Summer	Net Capability Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW[1]	MW	MW
Indian River	A	Brevard	GT	NG	DFO	PL	TK	0.2	06/89	Unknown	41,400	16[2]	18[2]
Indian River	B	Brevard	GT	NG	DFO	PL	TK	0.2	07/89	Unknown	41,400	16[2]	18[2]
Indian River	C	Brevard	GT	NG	DFO	PL	TK	0.2	08/92	Unknown	130,000	83[3]	88[3]
Indian River	D	Brevard	GT	NG	DFO	PL	TK	0.2	10/92	Unknown	130,000	83[3]	88[3]
Stanton Energy Center	1	Orange	ST	BIT	NA	RR	UN	UN	07/87	Unknown[4]	464,500	311[5]	311[5]
Stanton Energy Center	2	Orange	ST	BIT	NA	RR	UN	UN	06/96	Unknown	464,500	352[6]	352[6]
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	3	10/03	Unknown		184[7]	189[7]
Stanton Energy Center	B	Orange	CC	NG	DFO	PL	TK	3	02/10	Unknown	333,000	292	307
St. Lucie[8]	2	St. Lucie	ST	NUC	NA	TK	UN	UN	08/83	Unknown		60	62
Osceola Generating Station[9]	1	Osceola	GT	NG	DFO	PL	TK	3	12/2001	Unknown	197,000	157	157
Osceola Generating Station[9]	2	Osceola	GT	NG	DFO	PL	TK	3	12/2001	Unknown	197,000	157	157
Osceola Generating Station[9]	3	Osceola	GT	NG	DFO	PL	TK	3	6/2002	Unknown	197,000	157	157

NOTES:

[1] Nameplate ratings are reported for units which OUC maintains majority ownership. Values reported are for the entire unit (not just OUC's ownership share)

[2] Reflects an OUC ownership share of 48.8 percent.

[3] Reflects an OUC ownership share of 79.0 percent.

[4] As discussed throughout OUC's 2026 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026.

[5] Reflects an OUC ownership share of 68.6 percent. As of January 1, 2026, OUC's owns 100% of Stanton Energy Center 1.

[6] Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 3.4 percent.

[7] Reflects an OUC ownership share of 28.0 percent.

[8] OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.

[9] Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				Rural and Residential			Commercial	
Year	Population	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
HISTORY:								
2016	514,813	2.56	2,491	201,424	12,369	401	23,991	16,719
2017	576,536	2.79	2,481	206,959	11,987	424	24,323	17,440
2018	577,895	2.74	2,576	210,899	12,212	475	25,020	18,966
2019	615,376	2.85	2,599	216,113	12,026	474	25,751	18,424
2020	634,982	2.86	2,750	221,756	12,402	459	26,391	17,408
2021	631,387	2.76	2,701	228,707	11,808	461	27,128	16,997
2022	642,220	2.72	2,798	236,057	11,851	484	28,013	17,285
2023	633,874	2.62	2,857	242,199	11,795	506	28,065	18,020
2024	655,296	2.64	2,923	248,682	11,752	506	28,394	17,814
2025	653,828	2.57	2,971	254,550	11,670	529	28,833	18,331
FORECAST:								
2026	667,321	2.57	3,081	260,150	11,845	524	29,125	17,979
2027	679,116	2.56	3,197	265,673	12,035	530	29,405	18,030
2028	691,014	2.55	3,303	271,127	12,183	537	29,679	18,077
2029	703,645	2.54	3,410	276,531	12,331	544	29,944	18,153
2030	716,270	2.54	3,516	281,932	12,471	550	30,199	18,205
2031	728,497	2.54	3,631	287,326	12,638	556	30,448	18,268
2032	740,752	2.53	3,754	292,699	12,825	564	30,690	18,366
2033	752,927	2.53	3,878	298,053	13,012	572	30,925	18,485
2034	765,150	2.52	3,993	303,391	13,162	581	31,153	18,642
2035	777,672	2.52	4,113	308,705	13,324	591	31,374	18,842

Notes:
Represents total of OUC and St. Cloud.

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWH	Industrial Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
HISTORY:							
2016	3,506	5,811	603,333	0	61	142	6,601
2017	3,480	5,839	595,929	0	59	124	6,568
2018	3,513	5,709	615,262	0	61	146	6,769
2019	3,544	5,579	635,318	0	61	145	6,823
2020	3,336	5,301	629,406	0	62	131	6,740
2021	3,447	5,210	661,681	0	62	136	6,807
2022	3,557	5,102	697,124	0	63	141	7,042
2023	3,587	5,075	706,729	0	44	162	7,155
2024	3,638	5,103	712,958	0	62	167	7,295
2025	3,708	5,109	725,731	0	61	191	7,459
FORECAST:							
2026	3,689	5,115	721,258	0	62	172	7,529
2027	3,816	5,158	739,748	0	63	172	7,778
2028	3,905	5,199	751,185	0	63	172	7,981
2029	3,951	5,238	754,336	0	63	173	8,141
2030	3,990	5,275	756,413	0	64	173	8,292
2031	4,031	5,310	759,182	0	64	173	8,455
2032	4,079	5,344	763,352	0	64	173	8,634
2033	4,131	5,376	768,405	0	64	173	8,818
2034	4,190	5,407	774,894	0	65	173	9,002
2035	4,257	5,438	782,838	0	65	173	9,200

Notes:
Represents total of OUC and St. Cloud.

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
HISTORY:					
2016	1,100	278	7,979	0	231,226
2017	1,032	302	7,902	0	237,121
2018	1,040	189	7,998	0	241,628
2019	644	295	7,762	0	247,443
2020	665	220	7,625	0	253,448
2021	534	206	7,547	0	261,045
2022	505	217	7,764	0	269,172
2023	578	239	7,972	0	275,339
2024	575	337	8,206	0	282,179
2025	503	260	8,222	0	288,492
FORECAST:					
2026	278	266	8,073	0	294,390
2027	147	278	8,202	0	300,236
2028	111	288	8,379	0	306,005
2029	112	297	8,550	0	311,713
2030	114	306	8,712	0	317,406
2031	0	315	8,770	0	323,084
2032	0	325	8,959	0	328,733
2033	0	335	9,153	0	334,354
2034	0	345	9,347	0	339,951
2035	0	356	9,556	0	345,517

Notes:
Represents total of OUC and St. Cloud.
Historical "Sales for Resale" includes sales to various entities to which OUC provided power.
Forecast "Sales for Resale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.
"Net Energy for Load" may not match other Schedules due to rounding.

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2016	1,620	252	1,368	0	0	0.5	0.0	2.5	1,617
2017	1,638	255	1,383	0	0	0.4	0.0	5.0	1,633
2018	1,541	207	1,334	0	0	0.4	0.0	3.7	1,537
2019	1,634	199	1,431	0	0	0.5	0.0	3.4	1,630
2020	1,590	224	1,362	0	0	0.8	0.0	2.3	1,586
2021	1,653	246	1,404	0	0	0.6	0.0	1.9	1,650
2022	1,666	243	1,420	0	0	0.5	0.0	2.0	1,663
2023	1,795	241	1,551	0	0	0.8	0.0	1.6	1,792
2024	1,811	300	1,509	0	0	0.7	0.0	1.4	1,809
2025	1,822	198	1,622	0	0	0.5	0.0	1.7	1,820
FORECAST:									
2026	1,720	152	1,568	0	0	0.0	0.0	0.0	1,720
2027	1,649	35	1,614	0	0	0.0	0.0	0.0	1,649
2028	1,664	27	1,636	0	0	0.0	0.0	1.0	1,663
2029	1,641	27	1,613	0	0	0.0	0.0	1.0	1,640
2030	1,659	27	1,630	0	0	1.0	0.0	1.0	1,657
2031	1,666	0	1,664	0	0	1.0	0.0	1.0	1,664
2032	1,694	0	1,692	0	0	1.0	0.0	1.0	1,692
2033	1,724	0	1,721	0	0	1.0	0.0	2.0	1,721
2034	1,753	0	1,750	0	0	1.0	0.0	2.0	1,750
2035	1,786	0	1,783	0	0	1.0	0.0	2.0	1,783

Notes:
"Retail" represents total of OUC and St. Cloud. "Wholesale" represents peak demand for entities to which OUC provided wholesale power. Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of peaks and/or rounding.
Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual demand reductions associated with new participants in OUC's DSM programs.
Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual demand reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.
Historical "Wholesale" includes sales to various entities to which OUC provided power.
Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.
"Wholesale" and "Retail" are net of "Conservation" reductions.

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2015/16	1,320	243	1,077	0	0	0.4	0.0	1.3	1,319
2016/17	1,194	210	984	0	0	0.3	0.0	4.4	1,189
2017/18	1,410	182	1,228	0	0	0.3	0.0	4.7	1,405
2018/19	1,134	76	1,055	0	0	0.3	0.0	3.5	1,131
2019/20	1,160	67	1,090	0	0	0.8	0.0	2.0	1,157
2020/21	1,307	169	1,134	0	0	1.0	0.0	2.0	1,304
2021/22	1,348	190	1,156	0	0	0.7	0.0	1.7	1,346
2022/23	1,521	291	1,228	0	0	1.0	0.0	1.6	1,519
2023/24	1,351	221	1,128	0	0	0.7	0.0	1.0	1,349
2024/25	1,663	381	1,280	0	0	0.5	0.0	1.5	1,661
FORECAST:									
2025/26	1,326	94	1,231	0	0	0.5	0	0.4	1,325
2026/27	1,308	27	1,279	0	0	1.0	0	0.8	1,306
2027/28	1,345	20	1,322	0	0	1.6	0	1.2	1,342
2028/29	1,369	20	1,345	0	0	2.2	0	1.7	1,365
2029/30	1,394	21	1,368	0	0	2.9	0	2.2	1,389
2030/31	1,398	0	1,392	0	0	3.6	0	2.7	1,392
2031/32	1,424	0	1,416	0	0	4.3	0	3.2	1,416
2032/33	1,448	0	1,439	0	0	5.0	0	3.7	1,439
2033/34	1,474	0	1,464	0	0	5.8	0	4.3	1,464
2034/35	1,502	0	1,491	0	0	6.6	0	4.8	1,491

Notes:

"Retail" represents total of OUC and St. Cloud. "Wholesale" represents peak demand for entities to which OUC provided wholesale power. Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of peaks and/or rounding.
Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual demand reductions associated with new participants in OUC's DSM programs.
Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual demand reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.
Historical "Wholesale" includes sales to various entities to which OUC provided power.
Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.
"Wholesale" and "Retail" are net of "Conservation" reductions.

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
HISTORY:								
2016	7,992	1.2	12.3	6,601	1,100	278	7,979	55.4%
2017	7,934	0.8	31.0	6,568	1,032	302	7,902	55.3%
2018	8,033	0.8	34.7	6,769	1,040	189	7,998	59.4%
2019	7,778	1.0	14.3	6,823	644	295	7,762	54.4%
2020	7,558	1.6	9.0	6,740	665	220	7,625	52.2%
2021	7,570	11.5	11.4	6,807	534	206	7,547	52.2%
2022	7,770	1.1	4.8	7,042	505	217	7,764	53.3%
2023	7,983	1.9	8.5	7,155	578	239	7,972	50.8%
2024	8,216	1.7	8.2	7,295	575	337	8,206	51.8%
2025	8,234	1.0	10.4	7,459	503	260	8,222	51.6%
FORECAST:								
2026	8,077	1.0	3.0	7,529	278	266	8,073	53.6%
2027	8,211	2.0	7.0	7,778	147	278	8,202	56.8%
2028	8,391	2.0	10.0	7,981	111	288	8,379	57.5%
2029	8,569	4.0	15.0	8,141	112	297	8,550	59.5%
2030	8,737	6.0	19.0	8,292	114	306	8,712	60.0%
2031	8,800	7.0	23.0	8,455	0	315	8,770	60.2%
2032	8,996	9.0	28.0	8,634	0	325	8,959	60.5%
2033	9,196	10.0	33.0	8,818	0	335	9,153	60.7%
2034	9,396	12.0	37.0	9,002	0	345	9,347	61.0%
2035	9,611	13.0	42.0	9,200	0	356	9,556	61.2%

Notes:

"Retail" represents total of OUC and St. Cloud. "Wholesale" represents energy for entities to which OUC provided wholesale power. Energy may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to rounding.

Historical "Residential Conservation" and "Comm/Ind. Conservation" represent annual energy reductions associated with new participants in OUC's DSM programs.

Forecast "Residential Conservation" and "Comm/Ind. Conservation" represent cumulative annual energy reductions associated with new participants in OUC's DSM programs described in Section 5 of OUC's 2026 Ten-Year Site Plan.

Historical "Wholesale" includes sales to various entities to which OUC provided power.

Forecast "Wholesale" includes aggregated projected sales to City of Winter Park, City Mt. Dora, City of Chattahoochee, and Lakeland Electric as summarized in Section 2 of OUC's 2026 Ten-Year Site Plan.

"Wholesale" and "Retail" are net of "Conservation" reductions.

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2025 Actual		2026 Forecast		2027 Forecast	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	1,190	584	1,231	579	1,279	598
February	1,122	502	1,170	519	1,216	536
March	1,156	539	1,168	584	1,202	605
April	1,240	608	1,277	611	1,320	632
May	1,461	722	1,493	690	1,545	713
June	1,410	737	1,451	725	1,493	749
July	1,553	799	1,512	777	1,558	802
August	1,575	796	1,568	781	1,614	807
September	1,379	714	1,460	720	1,505	744
October	1,238	634	1,395	660	1,446	681
November	1,291	540	1,246	570	1,300	591
December	998	546	1,216	579	1,289	599

Notes:
Represents the total of OUC and St. Cloud retail peak demands and net energy for load. Wholesale sales are not included.
Peak demands may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to non-coincidence of OUC and St. Cloud peaks and/or rounding. NEL may not match other schedules and tables in OUC's 2026 Ten-Year Site Plan due to rounding.

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Nuclear		Trillion BTU	5	5	6	5	6	6	6	6	6	6	6	6
(2)	Coal		1000 Ton	793	1,036	696	632	0	0	0	0	0	0	0	0
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	28	4	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	3	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	26	0	0	0	0	0	0	0	0	0	0	0
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	43,247	47,009	40,700	38,942	52,827	52,050	51,106	49,299	50,154	43,834	38,034	39,568
(14)		Steam	1000 MCF	4,552	3,514	2,246	1,173	9,106	9,371	9,991	10,176	14,973	15,596	11,880	11,648
(15)		CC	1000 MCF	37,683	42,752	34,661	35,527	39,768	38,582	37,080	34,156	27,566	25,095	21,888	23,260
(16)		CT	1000 MCF	1,012	743	3,794	2,242	3,952	4,097	4,035	4,967	7,615	3,143	4,265	4,660
(17)	Other (Specify)		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
Represents fuel required to serve OUC and St. Cloud, and sales to wholesale customers.
Natural gas CC includes purchases from Stanton A PPA

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Firm Inter-Region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	433	469	503	496	504	502	503	503	505	503	503	503
(3)	Coal		GWH	1,608	2,105	1,398	1,281	0	0	0	0	0	0	0	0
(4)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	4	1	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH	0	1	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	2	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	2	0	0	0	0	0	0	0	0	0	0	0
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	5,753	5,059	5,443	5,341	6,789	6,601	6,398	6,093	5,911	5,203	4,487	4,696
(15)		Steam	GWH	384	287	225	119	817	791	827	874	1,409	1,453	1,094	1,079
(16)		CC	GWH	5,303	4,731	4,898	5,035	5,639	5,471	5,235	4,805	3,835	3,477	3,019	3,206
(17)		CT	GWH	65	41	320	187	333	339	336	414	667	273	374	411
(18)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	GWH	408	588	729	1,084	1,086	1,447	1,811	2,174	2,543	3,447	4,356	4,356
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	139	110	70	61	61	61	61	61	61	61	61	61
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	268	478	659	1,023	1,025	1,386	1,749	2,113	2,482	3,386	4,295	4,295
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(29)	Net Energy for Load		GWH	8,206	8,222	8,073	8,202	8,379	8,550	8,712	8,770	8,959	9,153	9,347	9,556

Notes:
Represents GWh required to serve OUC and St. Cloud, and sales to wholesale customers.
Total Net Energy for Load may not correspond to other Schedules due to rounding.
Natural Gas CC includes purchases from Stanton A PPA

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Firm Inter-Region Interchange		%	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)	Nuclear		%	5.3%	5.7%	6.2%	6.0%	6.0%	5.9%	5.8%	5.7%	5.6%	5.5%	5.4%	5.3%
(3)	Coal		%	19.6%	25.6%	17.3%	15.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(4)	Residual	Total	%	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)		Steam	%	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)		CC	%	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)		CT	%	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)		Other	%	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)	Distillate	Total	%	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)		Steam	%	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)		CC	%	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)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(13)		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	Natural Gas	Total	%	70.1%	61.5%	67.4%	65.1%	81.0%	77.2%	73.4%	69.5%	66.0%	56.8%	48.0%	49.1%
(15)		Steam	%	4.7%	3.5%	2.8%	1.4%	9.8%	9.3%	9.5%	10.0%	15.7%	15.9%	11.7%	11.3%
(16)		CC	%	64.6%	57.5%	60.7%	61.4%	67.3%	64.0%	60.1%	54.8%	42.8%	38.0%	32.3%	33.5%
(17)		CT	%	0.8%	0.5%	4.0%	2.3%	4.0%	4.0%	3.9%	4.7%	7.4%	3.0%	4.0%	4.3%
(18)	NUG		%												
(19)	Renewables	Total	%	5.0%	7.2%	9.0%	13.2%	13.0%	16.9%	20.8%	24.8%	28.4%	37.7%	46.6%	45.6%
(20)		Biofuels	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(21)		Biomass	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(22)		Hydro	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(23)		Landfill Gas	%	1.7%	1.3%	0.9%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%
(24)		MSW	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(25)		Solar	%	3.3%	5.8%	8.2%	12.5%	12.2%	16.2%	20.1%	24.1%	27.7%	37.0%	46.0%	44.9%
(26)		Wind	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(27)		Other	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(28)	Other (Specify)		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(29)	Net Energy for Load		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes:

Represents GWh required to serve OUC and St. Cloud, and sales to wholesale customers.
Natural Gas CC includes purchases from Stanton A PPA

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak
FORECAST:											
2026	1,556	584	0	0	2,140	1,720	420	27%	0	420	27%
2027	1,556	758	0	0	2,314	1,649	665	42%	0	665	42%
2028	1,556	758	0	0	2,314	1,663	651	40%	0	651	40%
2029	1,556	746	0	0	2,302	1,640	662	40%	0	662	40%
2030	1,556	820	0	0	2,376	1,657	720	43%	0	720	43%
2031	1,556	995	0	0	2,551	1,664	887	52%	0	887	52%
2032	1,556	877	0	0	2,433	1,692	742	42%	0	742	42%
2033	1,556	1,314	0	0	2,870	1,721	1,149	63%	0	1,149	63%
2034	1,556	1,700	0	0	3,256	1,750	1,506	81%	0	1,506	81%
2035	1,556	1,700	0	0	3,256	1,783	1,474	77%	0	1,474	77%

Notes:

"Firm Capacity Import" includes OUC's existing and future power purchase agreements, including renewables.

"System Firm Summer Peak Demand" includes OUC and St. Cloud peak demand, as well as OUC's wholesale power sales, and is non-coincident.

"Reserve Margin (MW)" calculated as "Total Available Capacity" minus "System Firm Summer Peak Demand."

"Reserve Margin (% of Peak)" calculated as "Reserve Margin (MW)" divided by "System Firm Summer Peak Demand" after adjusting for sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland. OUC is not responsible for providing reserves to Winter Park, Mt. Dora, Chattahoochee, or Lakeland.

"Scheduled Maintenance (MW)" is zero, as no units are scheduled for maintenance during peak periods.

Forecast "System Firm Summer Peak Demand" may not exactly match up with peak demands presented in the OUC's 2026 Ten-Year Site Plan due to coincidence and rounding.

Reflects anticipated dates by which the Osceola Generating Station Unit 2 will be capable of delivering power to OUC following completion of necessary maintenance and transmission system improvements (summer of 2026) . Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak
FORECAST:											
2025/26	1,889	456	0	0	2,345	1,325	1,020	81%	0	1,020	81%
2026/27	1,593	456	0	0	2,049	1,306	743	57%	0	743	57%
2027/28	1,593	556	0	0	2,149	1,342	807	60%	0	807	60%
2028/29	1,593	469	0	0	2,062	1,365	697	51%	0	697	51%
2029/30	1,593	469	0	0	2,062	1,389	673	47%	0	673	47%
2030/31	1,593	469	0	0	2,062	1,392	670	45%	0	670	45%
2031/32	1,593	219	0	0	1,812	1,416	396	26%	0	396	26%
2032/33	1,593	369	0	0	1,962	1,439	523	34%	0	523	34%
2033/34	1,593	619	0	0	2,212	1,464	749	45%	0	749	45%
2034/35	1,593	819	0	0	2,412	1,491	922	54%	0	922	54%

Notes:
"Firm Capacity Import" includes OUC's existing and future power purchase agreements, including renewables.
"System Firm Summer Peak Demand" includes OUC and St. Cloud peak demand, as well as OUC's wholesale power sales, and is non-coincident.
"Reserve Margin (MW)" calculated as "Total Available Capacity" minus "System Firm Summer Peak Demand."
"Reserve Margin (% of Peak)" calculated as "Reserve Margin (MW)" divided by "System Firm Summer Peak Demand" after adjusting for sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland. OUC is not responsible for providing reserves to Winter Park, Mt. Dora, Chattahoochee, or Lakeland.
"Scheduled Maintenance (MW)" is zero, as no units are scheduled for maintenance during peak periods.
Forecast "System Firm Summer Peak Demand" may not exactly match up with peak demands presented in the OUC's 2026 Ten-Year Site Plan due to coincidence and rounding.
Reflects anticipated dates by which the Osceola Generating Station Unit 2 will be capable of delivering power to OUC following completion of necessary maintenance and transmission system improvements (summer of 2026) . Capacity from Stanton Energy Center Unit 1 no longer included beginning summer 2026 as OUC anticipates placing the unit in extended cold shutdown by May 31, 2026.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const. Start	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability Summer	Net Capability Winter	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status
Stanton Energy Center	1	Orange	ST	BIT	N/A	RR	N/A	-	N/A	Unknown[1]	464,500	-453	-453	OS
Stanton Energy Center	2	Orange	ST	NG	N/A	PL	N/A	-	N/A	04/27	464,500	352[2]	350[2]	OT

Notes:

1. As discussed throughout OUC's 2026 10-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026. Changes to Net Capability for Stanton Energy Center Unit 1 represents reduction in output for OUC's 100% ownership share of Stanton 1 following unit being placed into extended cold shutdown.
2. Changes to Stanton Energy Center Unit 2 represents conversion from coal to natural gas. Net Capability shown is not incremental but rather the net capability following conversion.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:

(2) Capacity
a. Summer:
b. Winter:

(3) Technology Type:

(4) Anticipated Construction Timing
a. Field construction start-date:
b. Commercial in-service date:

(5) Fuel
a. Primary fuel:
b. Alternate fuel:

(6) Air Pollution Control Strategy:

(7) Cooling Method:

(8) Total Site Area:

(9) Construction Status:

(10) Certification Status:

(11) Status with Federal Agencies:

(12) Projected Unit Performance Data
Planned Outage Factor (POF):
Forced Outage Factor (FOF):
Equivalent Availability Factor (EAF):
Resulting Capacity Factor (%):
Average Net Operating Heat Rate (ANOHR):

(13) Projected Unit Financial Data
Book Life (Years):
Total Installed Cost (In-Service Year $/kW):
Direct Construction Cost ($/kW):
AFUDC Amount ($/kW):
Escalation ($/kW):
Fixed O&M ($/kW-Yr):
Variable O&M ($/MWH):
K Factor:

Notes:
As discussed throughout OUC's 2026 Ten-Year Site Plan, consideration of OUC's current existing generating resources (including existing PPAs), OUC's expected future PPAs, and OUC's current base-case load forecast indicates that OUC is projected to have adequate capacity to satisfy forecast reserve margin requirements through 2035 (the final year considered in the 2026 Ten-Year Site Plan). As such, no new capacity additions are included in the 2026 Ten-Year Site Plan.

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1) Point of Origin and Termination:

(2) Number of Lines:

(3) Right-of-Way:

(4) Line Length:

(5) Voltage:

(6) Anticipated Construction Timing:

(7) Anticipated Capital Investment:

(8) Substations:

(9) Participation with Other Utilities:

Notes:
OUC's 2026 Ten-Year Site Plan does not include any proposed directly associated transmission lines. Therefore, Schedule 10 is not applicable.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 6

OUC RESPONSE TO DOE RFI

OUC
The Reliable One®

April 22, 2026

VIA EMAIL

Alex Fitzsimmons
Under Secretary of Energy (Acting)
Director, Office of Cybersecurity, Energy Security & Emergency Response
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585
Attn: askcr@hq.doe.gov

Re: Response to Information Request for Stanton Energy Center

Dear Under Secretary Fitzsimmons:

Transmitted herewith is the Orlando Utilities Commission's (OUC) responses to the U.S. Department of Energy's (DOE) April 8, 2026 information request regarding the Stanton Energy Center. OUC recognizes the Department's responsibility to ensure the adequacy, reliability and security of the Nation's energy supply and appreciates the opportunity to support this important effort.

OUC has completed Exhibit 1 in full, providing detailed information regarding the Stanton Energy Center's generating units, operating characteristics, fuel usage, planned retirements, potential conversions, regulatory considerations and other matters identified in the Department's request.

OUC remains committed to maintaining reliable, affordable, resilient, and sustainable electric service for our customers and to coordinating with federal, state, and regional partners on matters affecting grid reliability and energy security. We appreciate DOE's engagement on these issues and stand ready to provide any additional information or clarification that may assist in your review.

Please let me know if you have any questions or need any additional information.

Sincerely,

C. Clint Bullock

Clint P. Bullock
General Manager & Chief Executive Officer
Orlando Utilities Commission

Enclosure:
Responses to DOE Exhibit 1 – Stanton Energy Center

Orlando Utilities Commission (OUC) Responses to U.S. Department of Energy's April 8, 2026 Information Request for Stanton Energy Center

Please see below for Orlando Utilities Commission (OUC)'s responses to the U.S. Department of Energy's April 8, 2026 *Information Request for Stanton Energy Center*.

1. **Please identify the full legal name of the generating facility, its physical address, the Facility ID Number, and also the owner and operator names.**

   Response:
   Stanton Energy Center
   5100 S. Alafaya Trail
   Orlando, Florida 32831
   Energy Information Administration Plant Code: 564
   Owner: Please see Table 1 below
   Operator: Please see Table 1 below

Table 1. Stanton Energy Center Owner/Operator Information

Unit Name	Owner	Operator
Stanton Energy Center Unit 1	Orlando Utilities Commission (100%)	Orlando Utilities Commission
Stanton Energy Center Unit 2	Orlando Utilities Commission (71.6%) Florida Municipal Power Agency (28.4%)	Orlando Utilities Commission
Stanton Energy Center Unit A	NextEra Energy (65%) Orlando Utilities Commission (28%) Florida Municipal Power Agency (3.5%) Kissimmee Utility Authority (3.5%)	NextEra Energy
Stanton Energy Center Unit B	Orlando Utilities Commission (100%)	Orlando Utilities Commission
Stanton Solar Farm	Deriva Energy (100%)	Deriva Energy
Kenneth P. Ksionek Community Solar	Greenwood Sustainable Infrastructure LLC (100%)	Greenwood Sustainable Infrastructure LLC

2. **Please identify the Generator/Unit Information for each unit at the facility, including the Generator/Unit Name, the types of fuel it uses, whether it is dual fuel, its nameplate capacity in MW and its operating status. For example, an acceptable response would be Unit 1, coal, not dual fuel, 125MW, down for periodic maintenance.**

   Response:
   Please see Table 2 below. Operating status is as of the date this response was prepared.

Table 2. Stanton Energy Center Unit Summary

Unit Name	Fuel Types	Dual Fuel	Nameplate Capacity	Operating Status
Stanton Energy Center Unit 1	Coal	N	464.5 MW	Operational
Stanton Energy Center Unit 2	Coal	N	464.5 MW	Operational
Stanton Energy Center Unit A	Natural Gas (Primary) Distillate Fuel Oil (Alternate)	Y	688 MW	Operational
Stanton Energy Center Unit B	Natural Gas (Primary) Distillate Fuel Oil (Alternate)	Y	333 MW	Operational
Stanton Solar Farm	Solar	N	5.1 MW	Operational
Kenneth P. Ksionek Community Solar	Solar	N	8.9 MW	Operational

3. **Please explain how the unit is currently used (e.g. peaking, baseload, backup), its planned retirement date (if applicable), whether retirement has been previously accelerated or delayed, the reasons for the planned retirement, and the relevant local, state, or federal laws related to retirement.**

   Response:

   Each of Units 1, 2, A, and B at the Stanton Energy Center are currently used as baseload/intermediate units, and retirement dates for the units have not been identified. In the event OUC decides to retire any of the units, OUC will do so in compliance with applicable local/state/federal laws related to retirement.

   In late 2021 OUC purchased three natural gas combustion turbines (with the ability to utilize fuel oil as a backup fuel). Referred to as the Osceola Generating Station, the units are owned and operated by OUC and provide OUC with 510 MW of generating capacity (each unit is 170 MW), which is more than the 453 MW from Stanton Energy Center Unit 1.

   In the 2022 timeframe, OUC considered retirement of Stanton Energy Center Unit 1 by the end of 2025. However, OUC has since determined the best course of action is to place Stanton Energy Center Unit 1 into extended cold shutdown by May 2026. While in extended cold shutdown, Stanton Energy Center Unit 1 will be maintained in a manner such that the unit would be capable of being brought on-line to be operational as needs may arise. This change took into account how OUC could utilize all of its generating resources to continue to reliably service its customers' energy requirements.

   Similar to other municipal utilities in Florida, OUC utilizes a 15 percent reserve margin for resource planning purposes. Considering OUC's current forecast of peak demand and existing generating resources, OUC's reserve margins are projected to exceed 15 percent through 2031 without considering the capacity associated with Stanton Energy Center Unit 1. OUC is in the process of evaluating whether keeping Stanton Energy Center Unit 1 in extended cold shutdown for a prolonged period of time is appropriate.

   With respect to Stanton Energy Center Unit 2, OUC currently anticipates making modifications to allow the unit to operate on 100 percent natural gas by the end of 2027. OUC will continue to evaluate these modifications before making a final decision related to implementation.

4. **If you were at some previous point considering a retirement or sale of the facility and are now considering delaying retirement or sale of the unit please describe the circumstances.**

   Response:
   The only unit at Stanton Energy Center that OUC had considered retiring is Stanton Energy Center Unit 1; however, as discussed in response to Question No. 3, OUC decided to place Stanton Energy Center Unit 1 into extended cold shutdown rather than retiring the unit. When initially contemplating retirement of Unit 1, and after the purchase of Osceola Generating Station, OUC had sufficient generating resources to allow it to continue to reliably serve its customer's energy requirements, and retirement of Unit 1 was anticipated to reduce costs to OUC's customers.

5. **If you are considering a retirement or sales of the unit, please identify and explain with detail and particularity:**
    a. **If the facility is not in an 1S0/RTO market how is a loss of generation from the planned retirement expected to be replaced?**
    b. **Are there any relevant local, state, or federal laws regarding generation from the type of facility at issue?**
    c. **Is it possible for the facility to operate on a going forward basis without conflicting with federal, state, or local laws? If so, for how long and under what operating conditions?**
    d. **Would continued operation of the facility/units planned for retirement result in significantly increased costs for consumers? If yes, how? Would these costs be offset by increased reliability?**

    Response:
    This question is not applicable as OUC is not considering retirement at this time of any units at the Stanton Energy Center.

6. **If you are considering a conversion to natural gas, please identify the planned conversion date and general timeline, explain whether the conversion will result in units maintaining or increasing nameplate capacity and/or an increase in capacity factor, and whether there will be a result in cost savings for customers.**

    Response:
    OUC currently anticipates making modifications to Stanton Energy Center Unit 2 to allow the unit to operate on 100 percent natural gas by the end of 2027. OUC does not anticipate that such modifications would affect the nameplate capacity or the net generating capacity. OUC will continue to evaluate these modifications before making a final decision related to implementation and such analysis will consider how changes in the operation of Stanton Energy Center Unit 2 will affect the capacity factor and cost to operate Unit 2 to support OUC's ability to continue to reliably serve its customers' energy needs.

7. **If you are considering a conversion to natural gas, please explain with detail and particularity the actions being taken to minimize the length of outage for the conversion (e.g. use of existing turbines), explain whether external factors (e.g. laws, company policy) are driving the conversion, and any other relevant information.**

    Response:
    OUC currently anticipates making modifications to Stanton Energy Center Unit 2 to allow the unit to operate on 100 percent natural gas by the end of 2027. When OUC moves forward with the modifications, OUC does not expect that the modifications will require Unit 2 to be out of service for an extended period of time and will perform this modification consistent with its scheduling criteria for major planned outages.

8. **Please explain with detail and particularity:**
    a. **Are there any major operating limitations for any units at the facility;**
    Response:
    There are no major operating limitations for any units at the Stanton Energy Center.

b. Are there any safety considerations with continued operations; and

Response:

There are no safety considerations with continued operations of any units at the Stanton Energy Center.

c. Are there any workforce, fuel availability, contractual, or permitting complications at issue?

Response:

There are no workforce, fuel availability, contractual, or permitting complications at the Stanton Energy Center.

9. Regarding each generating facility footprint, please identify and explain with detail and particularity:

a. The Balancing Authority;

Response:

OUC is a member of the Florida Municipal Power Pool (FMPP).

b. The Reliability Coordinator;

Response:

Florida Reliability Coordinating Council (FRCC).

c. The name of the state utility regulatory commission and its relevant regulatory authority as it relates to the facility; and

Response:

The Florida Public Service Commission (FPSC) is the state utility regulatory commission for the State of Florida. As a municipal electric utility, OUC's rates are not regulated by the FPSC. However, OUC has reporting obligations to the FPSC including reports on energy provided by OUC to its customers and wholesale entities, resource plans, numeric conservation goals (through the FPSC's Florida Energy Efficiency and Conservation Act requirements), and reports on renewable energy and conservation and demand-side management.

d. Any other relevant parties.

Response:

The units located at the Stanton Energy Center are operated and maintained in accordance with all applicable local/state/federal requirements.

10. If the facility is not in an ISR/RTO market, please explain with detail and particularity, how energy and capacity, as applicable, from the facility is purchased. Are there any unique requirements/laws that affect the sale of energy and/or capacity from the facility?

Response:

Energy from OUC's generating resources located at the Stanton Energy Center are utilized as part of OUC's generating system (which includes resources located at sites other than the Stanton Energy Center) through its membership in the Florida Municipal Power Pool (FMPP). FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 7

DOE ORDER NO. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

Printed with soy ink on recycled paper

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 8

OUC EIRP

SIEMENS
Ingenuity for life

Orlando Utilities Commission
2020 Electric Integrated Resource Plan Report

Orlando Utilities Commission
November 2020

Unrestricted

This page intentionally left blank.

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Legal Notice

This document was prepared by Siemens Industry, Inc., Siemens Power Technologies International (Siemens PTI), solely for the benefit of Orlando Utilities Commission. Neither Siemens PTI, nor parent corporation or its or their affiliates, nor Orlando Utilities Commission, nor any person acting in their behalf (a) makes any warranty, expressed or implied, with respect to the use of any information or methods disclosed in this document; or (b) assumes any liability with respect to the use of any information or methods disclosed in this document.

Any recipient of this document, by their acceptance or use of this document, releases Siemens PTI, its parent corporation and its and their affiliates, and Orlando Utilities Commission from any liability for direct, indirect, consequential or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability.

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

This page intentionally left blank.

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Table of Contents

1. Executive Summary 1-1
1.1 Situation 1-2
1.1.1 The EIRP Process 1-2
1.1.2 Considerations 1-2
1.2 Future Challenges and Opportunities 1-3
1.3 EIRP Consultants 1-4
1.4 Stakeholder Engagement 1-4
1.5 Objectives and Criteria 1-5
1.6 OUC Management Clean Energy Roadmap Recommendation: 1-9
1.6.1 The Optimized Portfolio 1-9
1.7 Next Steps ..... **Error! Bookmark not defined.**
2. EIRP Overview 2-1
2.1 Background on Orlando Utilities Commission 2-1
2.2 EIRP Central Considerations 2-2
2.2.1 Structured Approach 2-2
2.2.2 Attributes 2-3
2.2.3 Stakeholder Input 2-4
2.3 Strategies and Portfolios Analyzed 2-5
2.3.1 Original Pathways and Conditions 2-5
2.3.2 Calibration Portfolio 2-6
2.3.3 Net Zero CO_2 by 2050 2-8
2.3.4 100% Renewable by 2050 2-10
2.3.5 Coal Retirement 2022/2026 2-11
2.3.6 Gas Conversion 2026/2029 2-13
2.3.7 Gas Conversion 2036/2040 2-14
2.3.8 Wind-by-Wire 2-16
2.3.9 Modular Nuclear 2-17
2.4 Attributes and Metrics 2-19
2.4.1 Reliability 2-19
2.4.2 Affordability 2-20

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

2.4.3 Sustainability 2-20
2.4.4 Resiliency 2-21

3. Load Forecast 3-1

3.1 Load Forecasting Methodology 3-1
3.1.1 Energy Efficiency Impact 3-1
3.1.2 Distributed Generation (DG) Impact 3-2
3.1.3 Electric Vehicle (EV) Impact 3-2
3.1.4 Demand Response 3-3
3.2 Long-Term Net Energy and Demand Forecast 3-4

4. Environmental Considerations 4-1

4.1 CO_2 Pricing 4-1
4.2 Electric Vehicles used for CO2 Offsets 4-2

5. Resource Options 5-1

5.1 New Generation and Energy Storage Resources 5-1
5.2 Assumptions 5-1
5.2.1 Combined Cycle Gas Turbine 5-2
5.2.2 Simple Cycle Combustion Turbine 5-3
5.2.3 Battery Storage 5-4
5.2.4 Solar Photovoltaics (PV) 5-6
5.2.5 Onshore Wind and Wind-by-Wire 5-8
5.2.6 Small Modular Reactor (Nuclear) 5-8

6. Fuel Forecast 6-1

6.1 U.S. Natural Gas Market Outlook 6-1
6.2 Natural Gas Forecast Methodology 6-3
6.3 Coal Price Forecast 6-4

7. Stochastic Analysis 7-1

7.1 Introduction 7-1
7.2 Use of Stochastic Analysis 7-2
7.3 Stochastic Distributions 7-2
7.3.1 Load Distributions 7-2
7.3.2 Natural Gas Price Distributions 7-4
7.3.3 Coal Price Distributions 7-6

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

7.3.4 Emission Price Distributions 7-6
7.3.5 Capital Cost Distributions 7-7
7.3.6 Cross-Commodity Correlations 7-10

8. Analysis Results and Comparisons 8-11
8.1 Reliability 8-11
8.2 Affordability 8-12
8.3 Sustainability 8-14
8.4 Resiliency 8-15
8.5 Findings and Recommendations 8-19

9. OUC's Optimized Portfolio 9-1
9.1 Introduction 9-1
9.2 Optimized Portfolio Advantages 9-1
9.2.1 Reliability 9-3
9.2.2. Affordability 9-3
9.2.2 Sustainability 9-4
9.2.3 Resiliency 9-5

10. Challenges and Opportunities 10-6
10.1 Reliability 10-6
10.2 Affordability 10-6
10.3 Sustainability 10-6
10.4 Resiliency 10-6

Appendix A: Technology Cost and Performance Assumptions A-1

Appendix B: Stochastics B-1

Appendix C: Terms and Definitions C-1

Appendix D: Existing Unit Specifications and Model Topography D-1

Appendix E: List of Abbreviations E-1

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Table of Exhibits

Exhibit 1: Final Balanced Scorecard 1-7
Exhibit 2: Overall EIRP Process 1-8
Exhibit 3: Leading Portfolio and Optimized Portfolio Comparison 1-9
Exhibit 4: Optimized Portfolio Energy Resource Mix and CO_2 Emissions 1-11
Exhibit 5. Overall EIRP Process 2-2
Exhibit 6: EIRP Attributes and Definitions 2-3
Exhibit 7: Calibration and Candidate Portfolios 2-6
Exhibit 8: Calibration Portfolio Build-Out (2020-2050) 2-7
Exhibit 9: Calibration Portfolio Installed Capacity 2-8
Exhibit 10: Net Zero CO_2 by 2050 Portfolio Build-Out (2020-2050) 2-9
Exhibit 11: Net Zero CO_2 by 2050 Portfolio Installed Capacity 2-9
Exhibit 12: 100% Renewable by 2050 Portfolio Build-Out (2020-2050) 2-10
Exhibit 13: 100% Renewable by 2050 Portfolio Installed Capacity 2-11
Exhibit 14: Coal Retirement 2022/2026 Portfolio Build-Out (2020-2050) 2-12
Exhibit 15: Coal Retirement 2022/2026 Portfolio Installed Capacity 2-12
Exhibit 16: Gas Conversion 2026/2029 Portfolio Build-Out (2020-2050) 2-13
Exhibit 17: Gas Conversion 2026/2029 Portfolio Installed Capacity 2-14
Exhibit 18: Gas Conversion 2036/2040 Portfolio Build-Out (2020-2050) 2-15
Exhibit 19: Gas Conversion 2036/2040 Portfolio Installed Capacity 2-15
Exhibit 20: Wind-by-Wire Portfolio Build-Out (2020-2050) 2-16
Exhibit 21: Wind-by-Wire Portfolio Installed Capacity 2-17
Exhibit 22: Modular Nuclear Portfolio Build-Out (2020-2050) 2-18
Exhibit 23: Modular Nuclear Portfolio Installed Capacity 2-19
Exhibit 24: East Coast Hurricane Methodology 2-21
Exhibit 25: West Coast Hurricane Methodology 2-22
Exhibit 26: Gas Pipeline Disruption Methodology 2-24
Exhibit 27: Annual Average and Peak Load EE Reduction Estimates 3-2
Exhibit 28: Electric Vehicle Average and Peak Load Impact 3-3
Exhibit 29: Forecasted Net Energy Estimates (GWh) 3-4
Exhibit 30: Forecasted Net Peak Load (MW) 3-5
Exhibit 31: Expected Value CO_2 Price Projections (2019$/ton CO_2) 4-1
Exhibit 32: Combined Cycle Capital Cost Forecast, 2019$/kW 5-3
Exhibit 33: Simple Cycle CT Capital Cost Forecast, 2019$/kW 5-4
Exhibit 34: Battery Storage Capital Cost Forecast, 2019$/kW 5-5
Exhibit 35: Single-Axis Tracking Solar PV (2019$/kW) 5-7
Exhibit 36: Small Modular Reactor (Nuclear) All-In Capital Cost, 2019$/kW 5-9
Exhibit 37: Annual Henry Hub Natural Gas Forecast (2019$/MMBtu) 6-3
Exhibit 38: OUC Delivered Coal Price Outlook (2019$/MMBtu) 6-4
Exhibit 39: Forecasted Net Energy Load (GWh) Distribution 7-3

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 40: Forecasted Peak Load (MW) Distribution 7-4
Exhibit 41: Natural Gas (Henry Hub) Price Distribution (2019$/MMBtu) 7-5
Exhibit 42: ILB Minemouth Coal Price Distribution (2019$/MMBtu) 7-6
Exhibit 43: CO_2 Price Distribution (2019$/short ton) 7-7
Exhibit 44: 74.5 MW Solar Capital Costs Distribution (2019$/kW) 7-8
Exhibit 45: 50 MW Lithium-Ion 4-hour Battery Storage Capital Costs Distribution (2019$/kW) 7-9
Exhibit 46: Advanced 2x1 Combined Cycle Capital Costs Distribution (2019$/kW) 7-9
Exhibit 47: Advanced Simple Cycle Frame CT Capital Costs Distribution (2019$/kW) 7-10
Exhibit 48: Reliability Attribute Metrics and Results 8-12
Exhibit 49: Affordability Attribute Metrics and Results 8-13
Exhibit 50: Sustainability Attribute Metrics and Results 8-14
Exhibit 51: Resiliency Attribute Metrics and Results 8-15
Exhibit 52: East Coast Hurricane Detailed Results 8-16
Exhibit 53: West Coast Hurricane Detailed Results 8-17
Exhibit 54: Gas Pipeline Disruption Detailed Results 8-18
Exhibit 55: EIRP Key Findings 8-19
Exhibit 56: Final Balanced Scorecard 8-19
Exhibit 57: Optimized Portfolio Build-Out (2020-2050) 9-2
Exhibit 58: Optimized Portfolio Installed Capacity 9-2
Exhibit 59: Optimized Portfolio Revenue Requirements (2022-2030)**Error! Bookmark not defined.**
Exhibit 60: Optimized Portfolio CO_2 Emissions Stochastic Distributions 9-4
Exhibit 61: Percentage of Total Energy Generation (MWh) by Technology (2050) 9-5
Exhibit 62: Siemens PTI New Resource Technology Cost and Financial Assumptions A-4
Exhibit 63: Process for Developing Stochastic Distribution B-2
Exhibit 64: Flow Chart to Address Load Uncertainty B-3
Exhibit 65: Gas Stochastics Development Process B-5
Exhibit 66: Henry Hub and TranscoZ6-nonNY Volatility B-6
Exhibit 67: Process for Coal Price Stochastic B-7
Exhibit 68: Technique to Develop CO_2 Costs Distributions B-8
Exhibit 69: Cross Commodity Correlations B-9
Exhibit 70: Capital Costs Stochastics Methodology B-10

DRAFT

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

1. Executive Summary

Orlando Utilities Commission (OUC) operates as a statutory commission created by the legislature of the State of Florida. Established in 1923, OUC – The *Reliable* One, Orlando's hometown utility, is the second largest municipal utility in Florida and 14th largest municipal in the country, providing electric, water, chilled water and lighting services to approximately 250,000 customers in Orlando, St. Cloud and parts of unincorporated Orange and Osceola counties. The OUC Commission consists of five members, including the Mayor of the City of Orlando, who is an ex-officio member. Members must be OUC customers and at least one member must reside outside the City of Orlando limits in the unincorporated area of Orange County.

OUC's long history of Sustainability was reinforced in February 2020 when the utility adopted a new strategic plan. As part of its strategic commitments, OUC will continue to make significant investments in energy innovation – particularly in solar, energy storage, electric vehicles (EVs), efficiency and conservation through 2030.

- OUC has committed $420 million to solar technology. Further commitments include investing an additional $90 million in energy storage. As part of these investments, OUC has already committed to providing 270 megawatts of solar energy to customers.
- $45 million has been committed to innovative electrification programs including support for e-buses, dealership programs, and additional EV charging stations, bringing OUC's total installed charging stations from 200 currently to nearly 300 by Spring 2021 – maintaining Orlando's position as one of the Top 10 most-EV ready cities in the nation[1].
- OUC expects to meet its strategic commitment to achieve 1% of savings of retail sales in 2020. Additionally, OUC has a $30 million investment planned in efficiency and conservation efforts by 2030, including enhancements to low-income programs and technology solutions.

OUC Management recommends significantly reducing coal-fired generation no later than 2025 and eliminating it no later than 2027, using coal-to-gas conversion as a technology bridge, positioning solar as the main source of new energy, investing in energy storage, and leveraging other future clean technologies. The resulting recommendation balances the key Attributes of Affordability, Reliability, Resiliency and Sustainability.

[1] In 2012, Orlando was named one of the Top 10 Most EV-Ready Cities in the U.S. by PlugShare, a mobile app that helps EV owners find charging stations. In summer 2020, Orange County was recognized in a report presented by the League of Women Voters in Florida as one of five "top tier" counties for EV readiness. Rankings were based on four measures, including percent of EV sales compared to total registered cars and trucks, charging and fast-charging infrastructure, and policy.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

1.1 Situation

To prepare for a clean energy future, OUC has taken another critical step toward finalizing the Electric Integrated Resource Plan (EIRP).

1.1.1 The EIRP Process

The EIRP is an energy roadmap that guides how OUC generates and supplies electricity in a way that balances Affordability, Reliability, Resiliency and Sustainability through 2050. Currently, OUC relies on a diverse fuel mix of coal, natural gas, nuclear, solar and landfill gas. As confirmed by the OUC Board in February 2020's public strategy workshop, and in furthering OUC's decades-long commitment to Sustainability, the utility pledged to achieve Net Zero CO_2 Emissions by 2050 goal, as well as interim targets of 50% CO_2 emissions reduction by 2030 and 75% by 2040 compared to 2005 levels[2]. OUC's Net Zero CO_2 by 2050 commitment directionally aligns with City of Orlando Mayor Buddy Dyer's 2017 aspirational proclamation to achieve 100% renewable energy generation for Orlando by 2050.

EIRPs are standard, responsible, due-diligence practices for utilities that typically look across a 20-year horizon, as driving forces in the energy industry change. However, OUC extended the time horizon to 30 years to explore the feasibility of 100% renewable generation. With stakeholder engagement at its core, the EIRP process considers factors affecting power generation and transmission – from individual customer needs to broader issues such as the utilization of existing assets and resources, advances in renewable energy technologies, and potential events that could impact energy supply and demand (e.g., government regulations, hurricanes, etc.).

1.1.2 Considerations

Florida-specific factors were taken into consideration because renewable resources are limited relative to other regions in the country. Currently, wind, hydroelectric and geothermal are not economically and/or technically viable in Florida – and biomass and landfill gas, while possible resources, are available only in small quantities[3]. That leaves the state's utilities with one feasible renewable asset: sunshine – which poses its own challenges. With solar power, electricity is not produced at night or at scale on cloudy days. With an average of 277 partly cloudy days[4] per year in Orlando – nearly 76% of the year – intermittency is a concern, and backup resources are necessary to ensure that power is always available.

Transmission infrastructure, which facilitates the transfer of high-voltage energy between Florida and the rest of the country, is a major component when considering Resiliency of the system. Largely due to Florida being a peninsula, the state can import energy only from its northern border. Unlike many other states where there are

[2] Data from 2005 is a widely used baseline, including in the 2018 Paris Agreement.
[3] U.S. Energy Information Administration, Florida: State Profile and Energy Estimates – Analysis
[4] National Oceanic and Atmospheric Administration – Cloudy and Sunny Days Analysis

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted
DRAFT

multiple paths to receive high-voltage energy, Florida has a lower overall import capacity. Compared to California, which has physical capacity to import 20% of its power, Florida has a lower overall transmission import capacity of approximately 6% of total forecast summer peak load in 2020[5].

These realities restrict Florida's renewable energy portfolio until further technology advancements and additional transmission access alters the landscape. To combat this, as shown in the utility's strategic commitments in the prior section and the following recommendation, OUC is investing in a balance of sustainable solutions to propel Central Florida toward a cleaner, greener future.

This document summarizes the EIRP methodology, process, and findings that led to OUC Management's recommended clean energy roadmap to generate and supply electric power to our community while achieving the goal of Net Zero CO_2 Emissions by 2050.

1.2 Future Challenges and Opportunities

The transition from a fossil-based generating portfolio to a clean portfolio introduces both challenges and opportunities:

- **Intermittency***:* As intermittent energy resources, such as solar, expand their viability as primary energy generation sources, OUC must take steps to ensure energy sufficiency by adding more energy storage and portfolio diversity.
- **Rate Competitiveness***:* The cost, maturity and availability of technology advancements and supporting infrastructure must be balanced to ensure Affordability is maintained.
- **Limited Energy Diversity***:* Unlike other parts of the country, Florida's only viable renewable option is solar energy[6] – although wind-by-wire generation may become more widely available in the future. OUC will continue to evaluate and monitor emerging clean technologies, such as hydrogen, offshore wind and small modular nuclear power plants.
- **Transmission**: OUC will have greater reliance on transmission infrastructure. As a result, greater geographical diversity of renewable energy will be required to minimize the risk of extreme weather, and generation diversity will need to remain part of the OUC strategy.

[5] Various studies and reports presented at the Florida Reliability Coordinating Council (FRCC) regarding the Florida/Southern 500kV Interconnection and FRCC regional load forecasts

[6]"Florida has few other renewable energy assets. The state has no significant wind resources and no installed utility-scale wind power generating capacity, although some wind power components are manufactured in Florida. Potential for a small amount of additional hydroelectric generation exists in the northern part of the state that is not close to sea level." (Source: U.S. Energy Information Administration)

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

1.3 EIRP Consultants

OUC engaged Siemens PTI to support the development of the EIRP and to evaluate a list of energy portfolio "candidates" for the utility to consider. Siemens PTI developed and analyzed seven possible Candidate Portfolios designed to provide sufficient energy to meet OUC demand under expected conditions – and also achieve multiple Sustainability goals by 2050. To determine the best resource mix for OUC, these portfolios were evaluated on the basis of four key Attributes: Affordability, Reliability, Resiliency and Sustainability.

To facilitate the critical stakeholder engagement process for the EIRP, which was used to rank the four key Attributes, OUC also engaged Essence Partners, an independent, national marketing firm specializing in the energy sector.

1.4 Stakeholder Engagement

Key Points:

- Community engagement included a wide variety of options for the community to provide feedback.
- A 12-member, independent, Advisory Council met multiple times, and after analyzing community input, determined how key Attributes should be weighted: Reliability at 35%, Affordability at 24%, Sustainability at 22% and Resiliency at 19%.

Stakeholder engagement is the foundation of the EIRP process. To ensure that OUC captured a comprehensive vision for the community's energy future, the EIRP included input from stakeholders in Orlando, Orange County and St. Cloud. Stakeholders were represented through a 12-member, independent Advisory Council nominated by elected officials and staff from Orange County, the City of Orlando and the City of St. Cloud. Members represented a cross-section of the community, composed of residential and commercial customers, including community partners, environmental groups, OUC program participants, and Orange and Osceola County residents. The Advisory Council met in November 2019, January 2020, and virtually in March 2020.

An online survey received input from 1,377 participants. To increase community engagement, five in-person community forums were held, generating additional feedback from 306 community members. Commercial customers were also engaged in a forum and interviews. All forums offered education on the EIRP to provide participants with a basic level of understanding and an opportunity to vote on the key Attributes. Essence Partners conducted all forums and gathered and analyzed all voting data.

After gathering input from stakeholders, Essence Partners provided the voting data to the Advisory Council and facilitated the group's ranking of the key Attributes which determined how they would be weighted when scoring the Candidate Portfolios. The Advisory Council rankings were: Reliability, with the most weight at 35%, Affordability at 24%, Sustainability at 22% and Resiliency at 19%.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted
DRAFT

Definitions of Key Attributes

- **Reliability:** An electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.
- **Affordability:** An electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.
- **Sustainability:** An electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.
- **Resiliency:** An electric system's ability to adapt to uncontrollable events (such as weather extremes like hurricanes, major storms, heat waves, cloud cover, and other severe weather events), maintain physical and cyber security, and quickly bounce back following an interruption.

1.5 Objectives and Criteria

Key Points:

- All Candidate Portfolios were analyzed for their ability to meet key Attributes of Reliability, Affordability, Sustainability and Resiliency.
- OUC reviewed seven Candidate Portfolios.
- The Leading Portfolio meets OUC's goal of Net Zero CO_2 Emissions by 2050, as well as interim targets of 50% CO_2 emissions reduction by 2030 and 75% by 2040.

The main EIRP objectives were to develop a portfolio strategy that: 1) achieved the best performance relative to the Attributes of Reliability, Affordability, Sustainability and Resiliency required to meet our community's future energy needs, and 2) met OUC's strategic Net Zero CO2 Emissions by 2050 goal, as well as interim targets of 50% CO2 emissions reduction by 2030 and 75% by 2040.

Candidate Portfolios were developed using several different pathways and mathematical optimization techniques to achieve these objectives. Siemens PTI then used these objectives as guiding principles to develop, define and subsequently measure the performance of the following seven Candidate Portfolios using stochastic simulations.

1. **Net Zero CO2 2050 Portfolio** – designed to test a portfolio that achieves Net Zero CO_2 emissions by 2050.
2. **100% Renewable by 2050 Portfolio** – designed to test the performance of a 100% renewable OUC generation fleet by 2050.
3. **Coal Retirement 2022/2026 Portfolio** – designed to test retiring a Stanton coal unit in 2022 and the other in 2026, replacing that capacity with renewables and energy storage only, based on the Synapse Energy Economics Report (August 2018) – a review of the U.S. electric system completed by Synapse Energy Economics.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

4. **Gas Conversion 2026/2029 Portfolio** – designed to test converting a Stanton coal unit to natural gas in 2026 and the other in 2029.
5. **Gas Conversion 2036/2040 Portfolio** – designed to test converting a Stanton coal unit to natural gas in 2036 and the other in 2040.
6. **Wind-by-Wire Portfolio** – designed to test the impact of out-of-state wind capacity late in the forecast horizon.
7. **The Modular Nuclear Portfolio** – designed to test the impact of adding modular nuclear capacity.

In addition to the Net Zero CO_2 Emissions reduction by 2050 goal, each Candidate Portfolio was evaluated and ranked based on the four key Attributes using specific metrics for each:

- **Reliability:** Each portfolio was designed to meet or exceed the Reliability requirement of 100% energy sufficiency under expected conditions without reliance on neighboring utilities. Additionally, Siemens PTI measured this Attribute using metrics related to the first year of energy shortages, which occur when customer demand exceeds available supply resources (due to significant cloud cover during highest demand week occurring in August). The second metric is the technology diversity of the portfolio at the end of the forecast horizon.
- **Affordability:** To measure each Candidate Portfolio for Affordability, Siemens PTI used metrics related to the portfolio costs of generation and transmission, including fixed cost recovery, and the uncertainty of those costs over the 30-year planning horizon.
- **Sustainability:** Siemens PTI measured this Attribute by determining the probability of meeting the Net Zero CO_2 Emissions reduction by 2050 goal and interim targets, as well as the percentage of clean (non-CO_2 emitting technologies) energy generation in 2050.
- **Resiliency:** To measure each portfolio for Resiliency, Siemens PTI used scenario analysis that simulated system shocks such as hurricanes and gas pipeline disruptions, as well as metrics related to energy shortages.

The performance of the portfolios across all metrics is summarized in the Balanced Scorecard (Exhibit 1). Numerical scores indicate how each portfolio was ranked (where 1 is the best, and 8 is the worst) relative to other portfolios on a given metric. The final score is the weighted average ranking using the weights provided by the Advisory Council (Reliability, 35%; Affordability, 24%; Sustainability, 22%; Resiliency, 19%).

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 1: Final Balanced Scorecard

Attributes	Weight	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Reliability	35%	3.5	3.0	2.0	2.0	4.0	3.0	1.5
Affordability	24%	5.2	6.2	5.1	4.7	5.8	5.5	4.4
Sustainability	22%	1.5	1.5	1.0	2.0	1.0	1.8	1.5
Resiliency	19%	3.0	4.3	4.3	4.0	8.0	5.0	4.0
Total	**100%**	**3.4**	**3.7**	**3.0**	**3.0**	**4.5**	**3.7**	**2.7**

*These Portfolios meet all of the Interim Emission Targets
Scores: 1 is the best. 8 is the worst

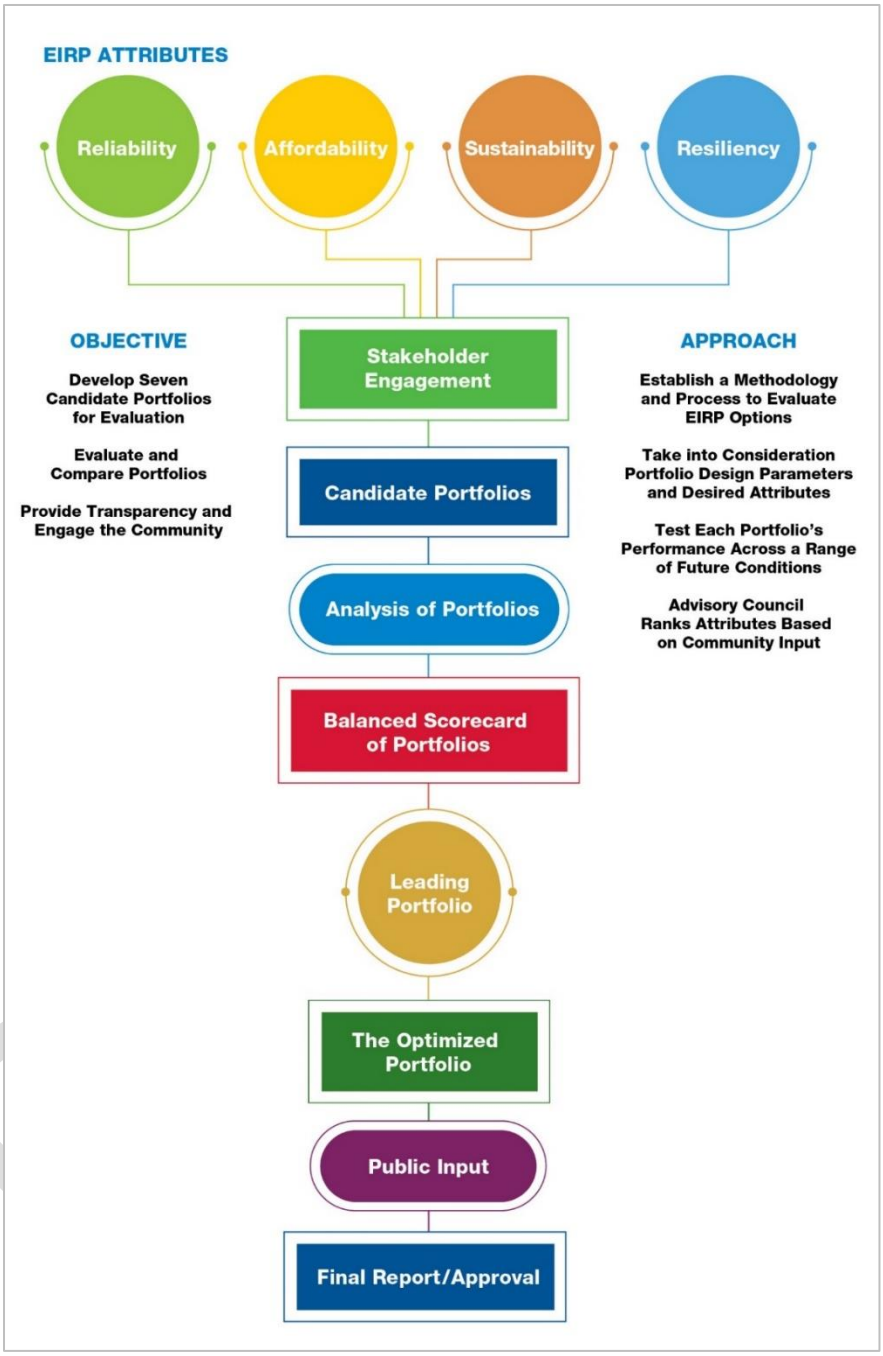
Source: Siemens PTI

While the Balanced Scorecard ranked Gas Conversion 2026/2029, Gas Conversion 2036/2040 and the Modular Nuclear as the most favorable Candidate Portfolios across the four Attributes, only Gas Conversion 2026/2029 accomplishes the Sustainability Attribute of achieving the Net Zero CO_2 Emissions by 2050 goal, as well as interim targets of 50% CO_2 Emissions reduction by 2030 and 75% by 2040. As a result, it became the "The Leading Portfolio."

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 2: Overall EIRP Process



Source: Costa, Siemens PTI

Unrestricted
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

1.6 OUC Management Clean Energy Roadmap Recommendation:

1.6.1 The Optimized Portfolio

Key Points:

- The Leading Portfolio was further refined into The Optimized Portfolio.
- This refinement meets OUC's Sustainability goals at the best value and increases levels of Reliability and Resiliency by limiting investments in new gas-fired generation and avoiding stranded costs.

Building upon the strengths of the Leading Portfolio, the Optimized Portfolio delivers on several key objectives including earlier coal retirement dates, accomplishment of interim Net Zero CO_2 Emissions, avoidance of stranded costs and long-term enhanced generation diversity.

The Balanced Scorecard was used as a guide for determining The Optimized Portfolio by including strategies that scored well and insights that were gained in the analysis of the Candidate Portfolios.

Exhibit 3: Leading Portfolio and Optimized Portfolio Comparison

	Gas Conversion 2026/2029 "Leading Portfolio"	Optimized Portfolio
Conversion Builds	2026, 2029	2025, 2027
Conversion Retirement	After 2050	By 2040
Primary New Energy Resources	Solar and Energy Storage	Solar, Energy Storage and Wind by Wire Generation
Non-FL Wind Generation	None	Contingent upon transmission access

Source: Costa

The elements of the strategy, along with the insights and validating metrics, allow OUC to achieve Net Zero CO_2 Emissions by 2050 goal, as well as interim targets of 50% CO_2 emissions reduction by 2030 and 75% by 2040, in directional alignment with the City of Orlando goals, while striking a balance of the four key Attributes – Reliability, Affordability, Sustainability and Resiliency.

Specifically:

- **Significantly reducing coal-fired generation no later than 2025 and eliminating it no later than 2027.** The C.D. McIntosh Unit 3, a 340-megawatt, primarily coal-fired unit in Lakeland, Florida, is expected to shutter by the end of 2024[7]. Both

[7] OUC owns a 40% share of this unit, which came online in 1982 and is operated by Lakeland Electric.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

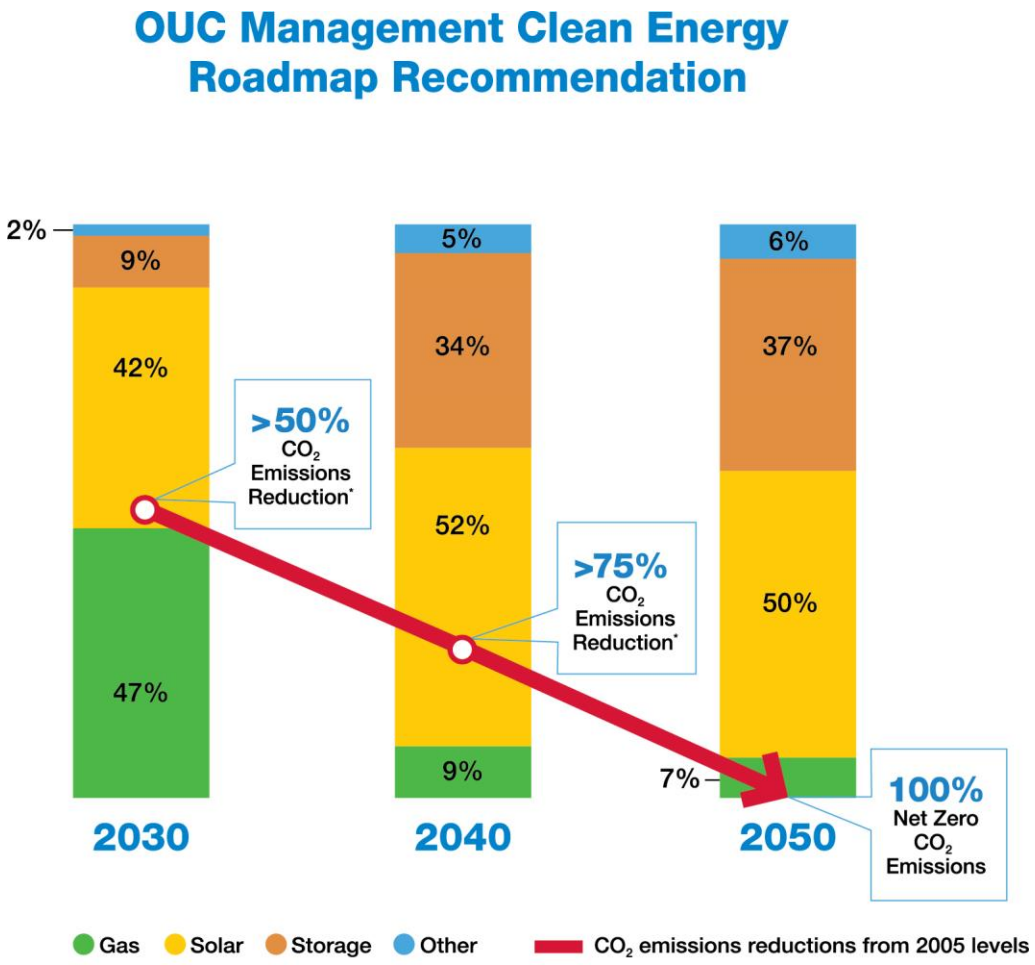
Stanton coal-fired units will be converted from coal to natural gas. The natural gas conversion units would be retired no later than 2040 to achieve greater Sustainability and avoid stranded costs.

- **Accelerating solar and energy storage as primary strategies.** Energy storage technologies will be used to provide energy during non-solar energy production periods.
- **Leveraging future clean technologies to ensure diversity for Reliability.** According to the EIRP analysis, the addition of wind-by-wire generation would greatly reduce the amount of solar and energy storage required to achieve energy sufficiency. Like solar, wind is an intermittent resource, but is highly complementary to solar generation. Generally, energy from wind resources is also available at different times of day, which is important for Reliability and Resiliency. While wind energy is currently not available for import into OUC's service territory due to transmission constraints, it is anticipated to be an option as access to transmission lines from the Midwest expand. OUC will continue to monitor its availability, along with other emerging clean resources such as hydrogen, offshore wind and small modular nuclear power plants.
- **Striving to maintain competitive rates while achieving strategic goals.** Advancements of this magnitude require significant investments. However, The Optimized Portfolio delivers the best value. Gas conversion capital costs are 5-10% of the cost of a new combined cycle gas plant, allowing for OUC to retire converted gas-fired units by 2040.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 4: Optimized Portfolio Energy Resource Mix and CO_2 Emissions



*Emissions reductions based on 2005 base levels
Other includes nuclear, wind and gas peaker
EV offsets used in 2050 only
OUC will significantly reduce coal-fired generation no later than 2025 and eliminate it no later than 2027.

Source: Costa

OUC will continue to monitor performance developments and technology enhancements for new and existing clean technologies, such as hydrogen and small modular reactors, to ensure the highest performance relative to the key Attributes.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

2. EIRP Overview

The EIRP is a comprehensive decision support tool and roadmap to aid OUC's objective of meeting its expected electric energy demand. The EIRP looks at a varying set of resources (generation, storage, demand side management) across Candidate Portfolios, subject to changing market circumstances, to ensure the OUC system remains Reliable, Affordable, Sustainable, and Resilient as well as flexible, diverse, and other more qualitative considerations.

2.1 Background on Orlando Utilities Commission

OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. Since 1923, OUC has provided residents and businesses with reliable electricity. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems to meet the requirements of its customers.

Established in 1923 by a special act of the Florida Legislature, OUC—The Reliable One is the second largest municipal utility in Florida and 14th largest municipal in the country. OUC provides electric, water, chilled water and/or lighting services to approximately 250,000 customer accounts in Orlando, St. Cloud and parts of unincorporated Orange and Osceola counties.

OUC is a member of the Florida Municipal Power Pool (FMPP), which consists of OUC, Lakeland Electric (Lakeland), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Electrical power for OUC is generated by Stanton B, a unit owned entirely by OUC, as well as units in which OUC maintains joint ownership and power purchases. OUC's available capacity as of January 1, 2020, including capacity from units owned by OUC, St. Cloud's entitlement to Stanton Energy Center Unit 2, and OUC's current power purchases (including natural gas, as well as landfill gas and solar resources), provides total net summer capacity of approximately 1,877 megawatts (MW) and total net winter capacity of approximately 1,902 MW[8].

OUC operates within the North American Electric Reliability Corporation (NERC) region of the SERC Reliability Corporation (SERC), which subsumed the Florida Reliability Coordinating Council (FRCC) in July 2019. Siemens PTI's analysis in this EIRP included

[8] Net seasonal capacity ratings as of January 1, 2020. Includes capacity owned by OUC and St. Cloud, as well as OUC's contractual power purchases.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

the broader, newer SERC region. Presently, OUC has ownership interests in four electric generating plants. Appendix D summarizes OUC's generating facilities:

- Stanton Energy Center Units 1 and 2, Stanton A, and Stanton B
- Indian River Plant Combustion Turbine Units A, B, C, and D
- Lakeland Electric McIntosh Unit 3 (To be retired 12/1/2024 per Lakeland)
- Florida Power & Light Company (FPL)St. Lucie Unit 2 Nuclear Generating Facility

2.2 EIRP Central Considerations

2.2.1 Structured Approach

For each of the portfolio options, the EIRP followed a process designed to identify the preferred course of action that balances the key Attributes of Reliability, Affordability, Sustainability, and Resiliency, further discussed in Section 2.2.2.

Exhibit 5. Overall EIRP Process

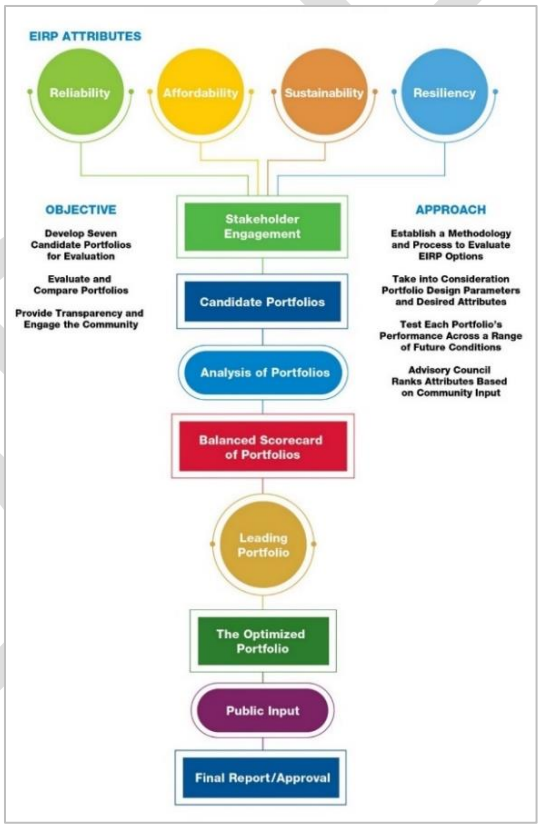


Exhibit 5 depicts the process followed to conduct this EIRP study.

1. Develop objectives, attributes, metrics and overall assumptions.
2. Identify resources that reasonably could be included in plans to meet the load including both supply and demand-side resources (screening).

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

3. Produce a load projection through 2050 showing fuel costs, emission costs, technology costs and performance (e.g. heat rates, capacity factors etc.) to be applied to the existing and new resource options.
4. Develop portfolios under the various parameters that meet certain pathways and conditions. These portfolios follow each scenario or pathway and used to perform additional risk analysis that subjects each portfolio to a wide range of future outcomes.
5. Perform Stochastic Modeling through 200 iterations (range of uncertainties) for each Candidate Portfolio to assess how well each portfolio performs under a range of market, technology, and regulatory uncertainties.
6. Prepare a balanced scorecard using the objectives and metrics defined in step 1 to rank supply options and select the Leading Portfolio.
7. Adjust the Leading Portfolio to produce the Optimized Portfolio.
8. Prepare a report with findings and recommendations for next steps.

2.2.2 Attributes

While Affordability is a key fundamental Attribute, the EIRP was centered on more than just costs. Ultimately, the Leading Portfolio for OUC is one that performs best against all relevant Attributes and metrics over a range of future conditions, while also accounting for non-analytical, qualitative considerations. As with any integrated resource plan, there will be tradeoffs between the competing objectives of Reliability, Sustainability, Affordability, and Resiliency. Exhibit 6 summarizes the metrics used in the evaluation of Candidate Portfolios.

Exhibit 6: EIRP Attributes and Definitions

ATTRIBUTES	DEFINITION
Reliability	an electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.
Affordability	an electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.
Sustainability	an electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.
Resiliency	An electric system's ability to adapt to uncontrollable events (such as weather extremes like hurricanes, major storms, heat waves, cloud cover, and other severe weather events), maintain physical and cyber security, and quickly bounce back following an interruption.

Source: Siemens PTI

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

2.2.3 Stakeholder Input

Essense Partners launched OUCRoadmap.com in May 2019 as the central stakeholder engagement hub for the EIRP. OUC customers and stakeholders were directed to the microsite to learn about the EIRP process and provide their input on the direction of the EIRP. Website users were required to watch a short video detailing what an EIRP is, why OUC is engaging in this process, and the importance of the four Attributes (Reliability, Resiliency, Affordability, and Sustainability) before accessing the input form.

The input form for customers included both a ranked choice question and free-response questions. The ranked choice question assessed the relative importance of four Attributes in relation to OUC's electric energy future. Free-response questions offered an area to address any additional concerns and explanations for why the customer ranked the Attributes in the order they chose.

Community members and stakeholders were also invited to a series of five, in-person community forums, hosted in the Orlando and St. Cloud areas in December 2019 and January 2020. Participants were given a presentation by Essense and Siemens, based on the information presented on OUCRoadmap.com, and were shown the video hosted on the microsite. After the presentation and video, participants were given the same Attribute ranking and free response questions as the ones on the microsite.

On January 29, a commercial forum was held at the Orlando Economic Partnership's office in downtown Orlando. To maintain consistency with residential community forums, commercial customers were shown the same presentation given by Essense and Siemens and were shown the same EIRP overview video. After watching the video, attendees were asked to rank the four Attributes and provide justifications for their rankings. Concurrently, Essense conducted one-on-one interviews with representatives from OUC's key accounts, defined as the largest commercial customers in terms of electric energy usage. Interviewees were asked to watch the video prior to meeting with Essense. After discussing the purpose and goals of the EIRP, interviewees then ranked the Attributes and provided justifications for their rankings.

The rankings and feedback from the online input form, the community forums, the commercial forum and the key account interviews were then presented to the Advisory Council. Throughout this process, Advisory Council members were also advised to engage with members of the stakeholder groups they represented. Members were then asked to rank the Attributes based on the input received from the four primary engagement opportunities and from their own interactions with community members. The final Advisory Council vote was given to Siemens as the stakeholder recommendation for Attribute weights.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

2.3 Strategies and Portfolios Analyzed

The overarching objective of this EIRP is to identify a portfolio of generation resources that best aligns across all key OUC Attributes of Reliability, Affordability, Sustainability, and Resiliency. Specifically, the Candidate Portfolios were designed to satisfy the two underlying requirements: 100% reliable and meet OUC's Net Zero CO_2 targets by 2050The EIRP process was designed to adapt with the analysis, incorporating updated market information, operational considerations, and logistical limits as they became available.

The process began with the development of a Calibration Portfolio, which served as a business-as-usual (BAU) outlook of expected market conditions and expected load. The Calibration Portfolio is based on the status quo of today's policies and regulations, thus serving as a benchmark to measure the performance of other portfolios that are designed to meet potential policy and regulation goals.

Using the same load and market forecasts as in the Calibration Portfolio, the process then advanced to the development of Pathways and Conditions to be evaluated in comparison with the project goals. The defined pathways and conditions and the role they served in the analysis are described in further detail in the section following.

2.3.1 Original Pathways and Conditions

To meet the objectives set out by this EIRP report, OUC and Siemens PTI developed multiple pathways and conditions to provide the ability to observe different ways to meet these objectives. Developing these pathways and conditions provides guidelines for the design of the Candidate Portfolios.

Original Pathways

The 2050 Pathways in the original EIRP process included five potential Pathways:

1. **Net Zero CO2 by 2050:** Both CO_2-free and CO_2-generating resources are used.
2. **100% Renewable Energy by 2050 w/ Intermediate Targets:** Meets the City of Orlando's target of generating 100% renewable energy by 2050.
3. **100% Renewable Energy by 2050 w/ Intermediate Targets including Nuclear:** Same as Pathway 2 but with Nuclear and Biomass included as potential resources.
4. **100% Net Zero CO2 by 2050 (OUC+FL):** Same as Pathway 1 but with all Florida Utilities required to offset their CO_2.
5. **Stanton Plant Retirement (Stanton Phase-Out):** Follows the first unaffiliated Synapse report (circa 2018) that posits the retirement of the Stanton 1 coal unit and the Stanton 2 coal unit, with only renewable energy and storage capacity allowed to backfill.

Using these five Pathways, the development process of the Candidate Portfolios was initiated. Each Candidate Portfolio has a different capacity expansion build-out but

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

ensures that it follows the requirements set out by at least one of the pathways described to achieve OUC's Sustainability targets. The process began by meeting the load outlook with a combination of resources through an optimization process.

Conditions

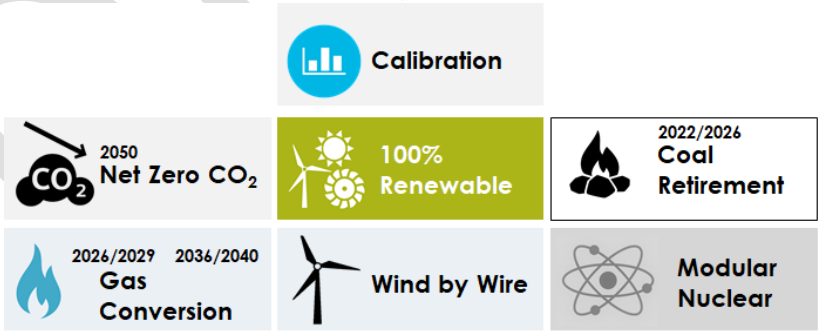
The EIRP process also included three potential future national market conditions, which were used to guide the development of portfolios for evaluation:

1. **High Technology:** In this future, technology advances lead to substantial demand growth; breakthrough advances in renewable energy and storage technologies incentivize and catalyze deployment, reducing the need for backup dispatchable gas and leading to increased coal retirements.
2. **Low Economy/High Regulation:** In this future, heavy regulations on CO_2 and fossil fuels lead to high CO_2, natural gas, and coal costs, more coal retirements, an acceleration of renewable energy via mandates, and a low level of load growth from a sluggish economy.
3. **High Economy/Low Regulation:** In this future, no significant U.S. regulations are promulgated. Economic growth and load growth are relatively robust. Natural gas prices rise with strong load growth, and coal retirements are extended, which creates headwinds for renewable energy deployment.

Portfolios

Together, these five Pathways and three conditions were the basis for developing and optimizing a total of seven Candidate Portfolios shown in Exhibit 7.

Exhibit 7: Calibration and Candidate Portfolios



Source: Siemens PTI

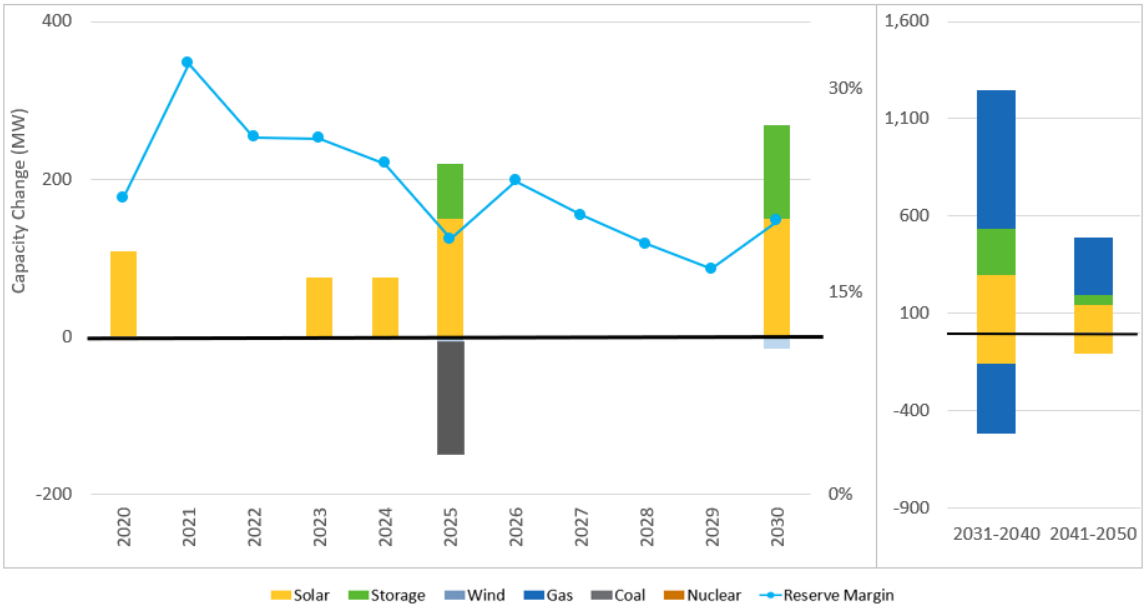
2.3.2 Calibration Portfolio

The Calibration Portfolio serves as a business-as-usual (BAU) portfolio which is used to benchmark the metrics of the Candidate Portfolios. Since this is a BAU case, it does not account for meeting any Net Zero CO_2 Targets. This portfolio mainly adds natural gas

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

capacity as well as some solar and storage units. These resources were chosen following economics and portfolio diversity incentives. Similar to the Candidate Portfolios, the Calibration Portfolio is able to serve all of OUC's load without having to rely on any purchases or sales. Most of the costs that occur in this portfolio are a result of the capital costs from building the natural gas-fired units, as well as the infrastructure needed to increase the natural gas transportation for the added natural gas capacity. One aspect that differentiates this portfolio from the Candidate Portfolios is that the reserve margin remains relatively low throughout the whole forecast. Also, this portfolio maintains the Stanton coal units, keeping the costs low compared to other portfolios that replace the coal units with renewable energy or convert the units to natural gas-fired units. The portfolio build-out is outlined in Exhibit 8 with a detailed break-out in the 2020-2030 timeframe.

Exhibit 8: Calibration Portfolio Build-Out (2020-2050)

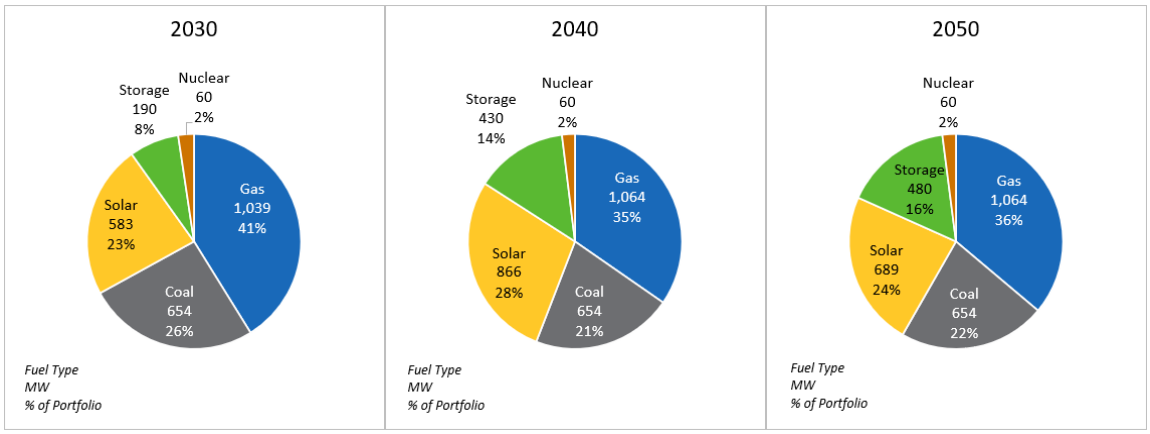


Source: Siemens PTI

To gain a better understanding of the resource diversity within the Calibration portfolio, Exhibit 9 provides the installed capacity in 2030, 2040, and 2050. As Exhibit 9 shows, the Calibration Portfolio manages to maintain a highly diverse portfolio with each technology representing a balanced portion of the total capacity mix. The total added capacity for each technology within the forecast time frame is: 996 MW solar, 480 MW Storage, 1,010 MW natural gas-fired capacity. The retirements for this portfolio per technology are: 108 MW solar (PPAs and contracts' expiration), 360 MW natural gas-fired plants (Stanton A PPA expiration), 144 MW coal plants (OUC's CD McIntosh portion).

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 9: Calibration Portfolio Installed Capacity



Source: Siemens PTI

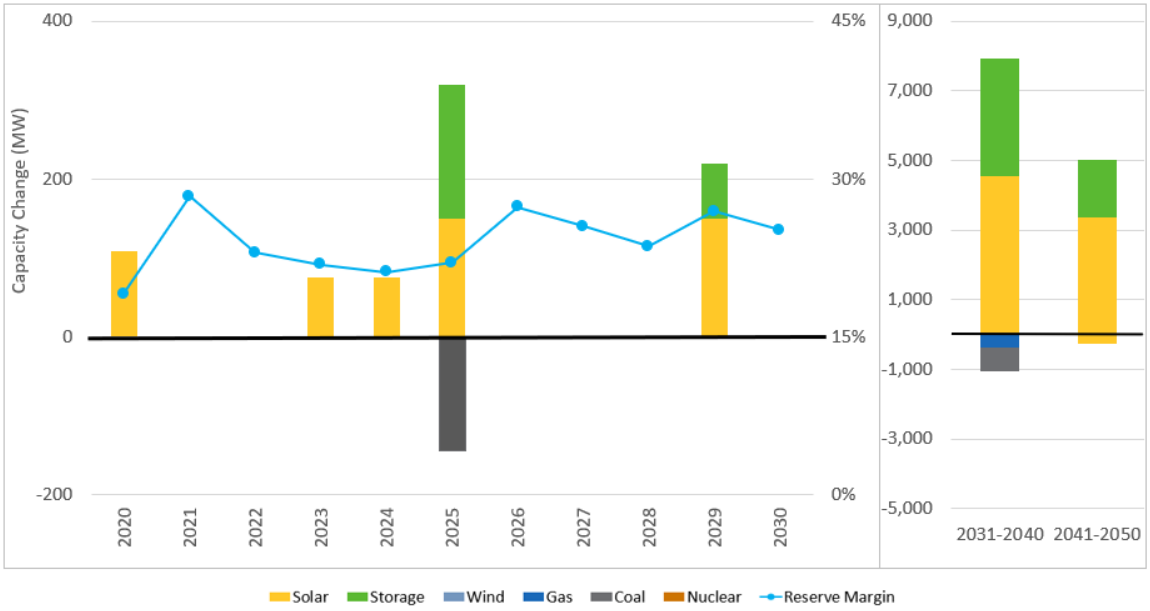
2.3.3 Net Zero CO_2 by 2050

The Net Zero CO_2 by 2050 Portfolio retires the Stanton 1 and 2 coal units in 2036 and 2040. Solar and storage additions are utilized to replace the capacity lost from retiring the Stanton coal units. As Exhibit 10 shows, when a dispatchable fossil-fuel fired unit is retired, the amount of solar and storage capacity needed to counter the loss in capacity far exceeds the capacity lost from the retirement of the fossil units. Solar energy is an intermittent resource for electricity generation, so it is not a one-to-one replacement for fossil plants. Storage can be utilized to capture solar energy and dispatch it later in the day when solar energy is not available. However, to have excess energy to charge the battery storage, extra solar capacity is built with the sole purpose to charge the battery storage. Additionally, for this analysis, the battery storage units are able to store 4 hours of energy, requiring extra storage capacity to ensure that all demand during non-solar hours is served. This trend drives up the reserve margin of the portfolio, making the reserve margin a less important metric to ensure energy sufficiency in high renewable/storage portfolios. This trend can be observed in all Candidate Portfolios discussed in this EIRP report.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

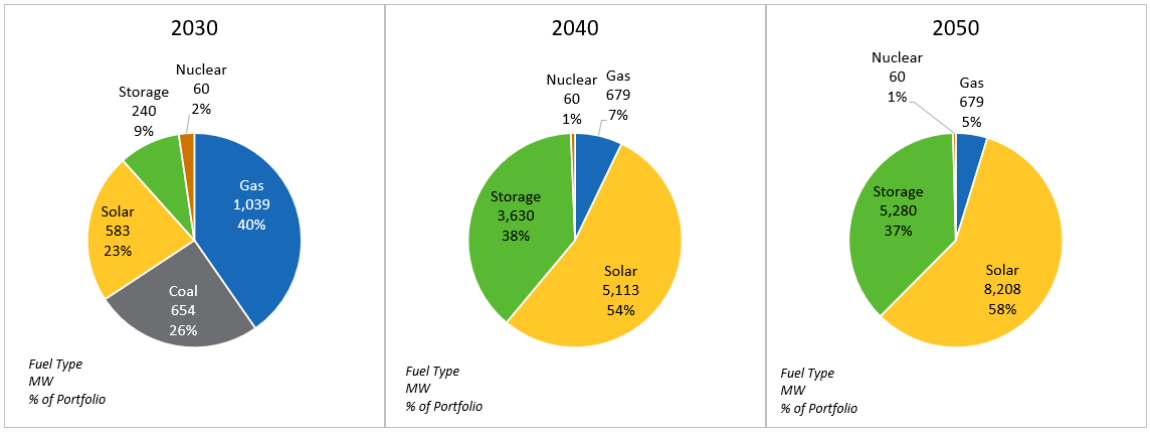
Exhibit 10: Net Zero CO_2 by 2050 Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Because the Net Zero CO_2 by 2050 Portfolio retires the Stanton coal units to meet the Net Zero CO_2 target, the portfolio ends up with a much less diverse portfolio build-out. Exhibit 11 shows the installed capacity by technology within this portfolio. In 2030, when the coal units are still online, the portfolio mix remains diverse with each resource representing a fair balance of the resource mix. The total added capacity per technology for this portfolio is: 8,452 MW solar, 5,280 MW storage. The retirements per technology for this portfolio are: 108 MW solar (PPAs and contracts), 360 MW natural gas-fired plants (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 11: Net Zero CO_2 by 2050 Portfolio Installed Capacity



Source: Siemens PTI

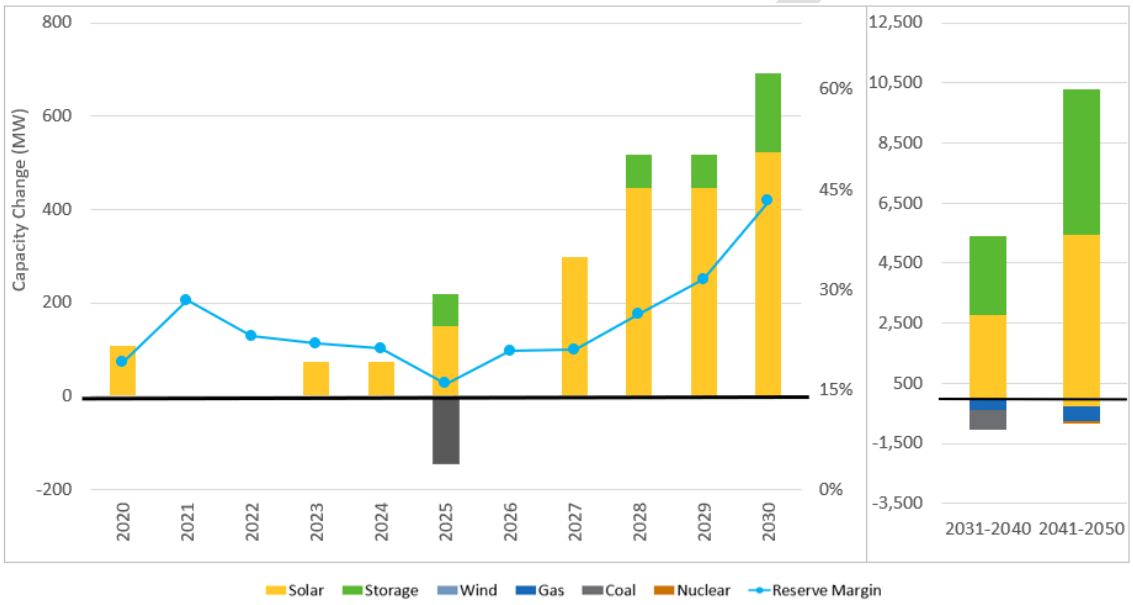
DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

2.3.4 100% Renewable by 2050

The 100% Renewable by 2050 Portfolio retires all the fossil, nuclear, and landfill gas units by 2050. However, compared to the Net Zero CO_2 by 2050 Portfolio, this portfolio maintains both coal units until 2040. OUC's portion of the St. Lucie powerplant is retired (or sold) by 2043. The Stanton A and B combined cycle units are retired by 2044 and 2048. Finally, the Indian River gas peaker units are retired by 2049. Thus, by 2050 this portfolio operates solely on solar and storage capacity. As a result, by the end of the forecast the reserve margin increases by almost 300%.

Exhibit 12: 100% Renewable by 2050 Portfolio Build-Out (2020-2050)

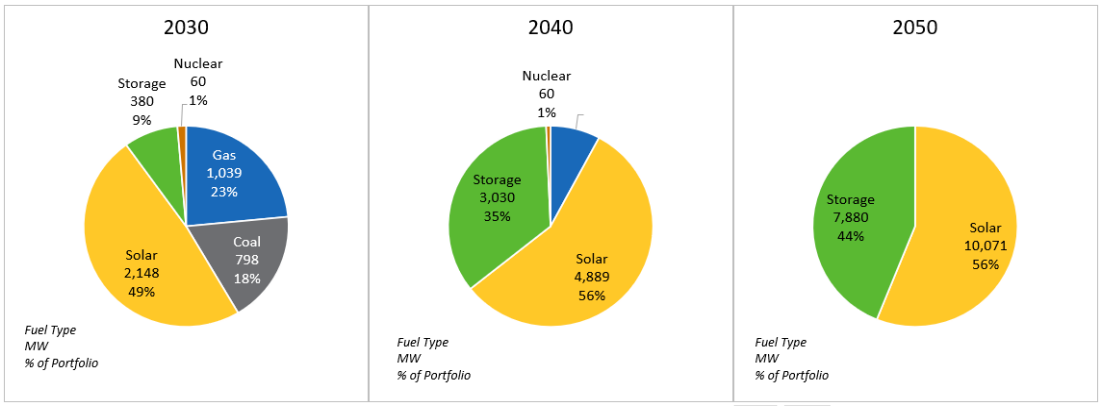


Source: Siemens PTI

Since the 100% Renewable by 2050 Portfolio is only able to utilize solar and storage capacity to back-fill the retirement of coal, gas, nuclear, and landfill gas, the portfolio ends up with a build-out much less diverse than all other Candidate Portfolios by 2050 (Exhibit 13). Similar to the Net Zero CO_2 by 2050 Portfolio, this portfolio maintains a diverse portfolio in 2030. However, after the retirements of the Stanton coal units we can observe the impact on the diversity of the portfolio in 2040. By 2050, the only resource within the portfolio technology mix are solar and storage. The capacity additions per technology for this portfolio are: 10,315 MW solar and 7,880 MW storage. The capacity retirements per technology for this portfolio are: 108 MW solar (PPAs and contracts), 875 MW gas-fired (Stanton A PPA, OUC's portion of Stanton A and B, Indian River peaker units), and 801 MW coal (OUCs portion of CD McIntosh and Stanton 1 and 2 coal units).

Unrestricted
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 13: 100% Renewable by 2050 Portfolio Installed Capacity



Source: Siemens PTI

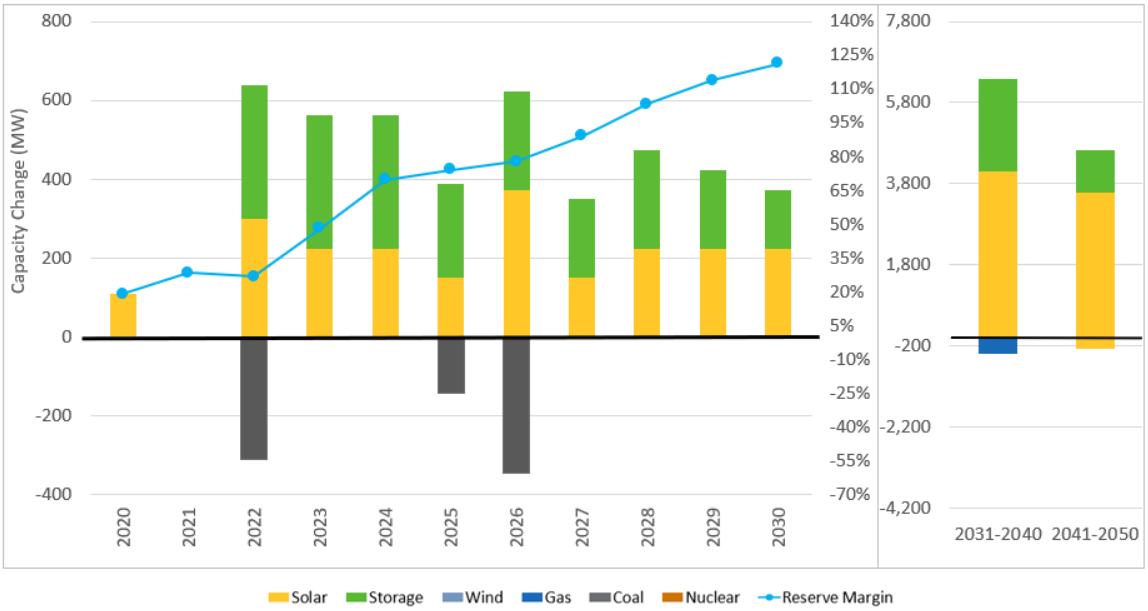
2.3.5 Coal Retirement 2022/2026

The Coal Retirement 2022/2026 Portfolio is based on the 2019 report conducted by Synapse. In Synapse's report, the Stanton 1 coal unit is retired in 2020 and the Stanton 2 unit is retired soon thereafter. For this EIRP report, Stanton 1 and Stanton 2 are retired by 2022 and 2026. The only technologies used to replace the coal units are solar and storage capacity. Because this portfolio retires the coal units without converting them to natural gas, we observe a heavy storage and solar build-out early in the forecast. Since this portfolio only retires Stanton 1 and 2, the expected retirement of CD McIntosh Jr. 3 coal unit by 2024 and the expiration of the Stanton A PPA in 2032, the required solar and storage build-out is lower than the 100% Renewable by 2050 Portfolio. Exhibit 14 shows the build-out of the Coal Retirement 2022/2026 Portfolio with a detailed build-out for the 2020-2030 timeframe, as well as a high-level overview of the capacity changes from 2030-2050.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

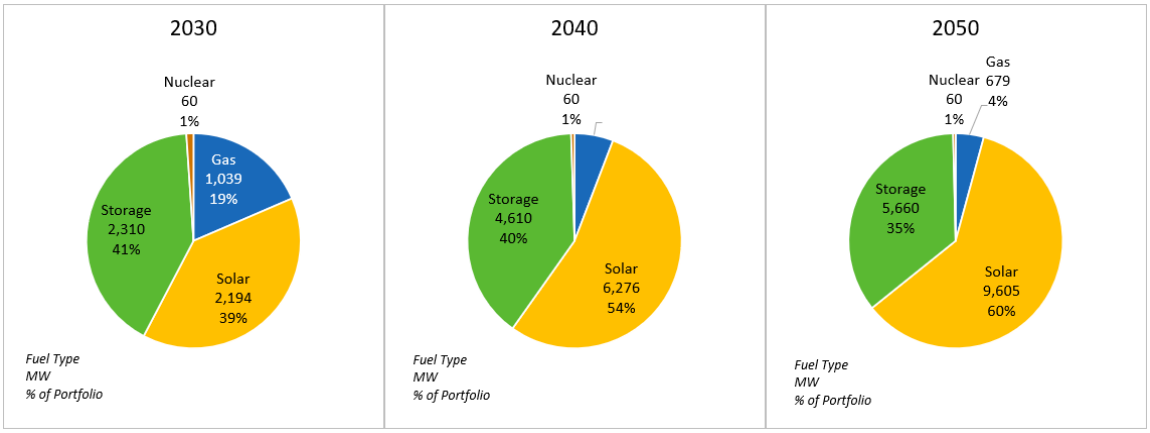
Exhibit 14: Coal Retirement 2022/2026 Portfolio Build-Out (2020-2050)



Source: Siemens PTI

The Coal Retirement 2022/2026 Portfolio retires the coal units early and replaces them with storage and solar capacity, thus impacting the resource diversity of the portfolio early in the forecast (Exhibit 15). By 2030, most of the capacity remaining in the portfolio consisting of solar and storage (80%). The capacity additions for this portfolio per technology are: 9,868 MW solar and 5,660 MW storage. The retired capacity per technology for this portfolio is: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 15: Coal Retirement 2022/2026 Portfolio Installed Capacity



Source: Siemens PTI

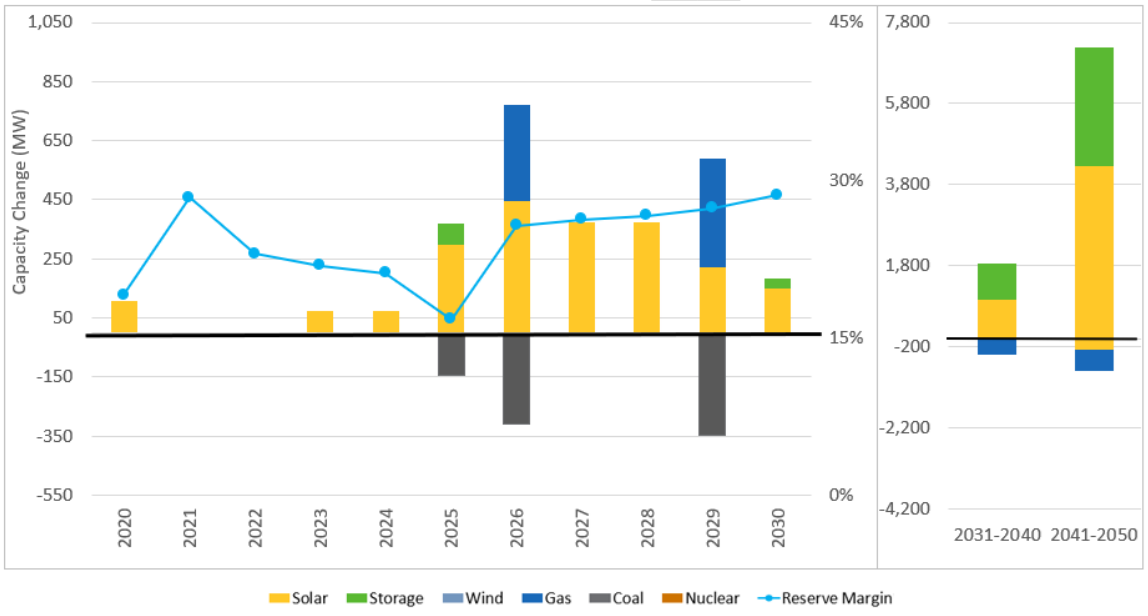
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

2.3.6 Gas Conversion 2026/2029

Like the Net Zero CO_2 by 2050 Portfolio, the Gas Conversion 2026/2029 Portfolio is designed to achieve the Net Zero CO_2 target by 2050. Using this logic, the Gas Conversion 2026/2029 Portfolio maintains some dispatchable fossil-fuel fired capacity, significantly reducing the required solar and storage builds to meet OUC's load.

In this portfolio the Stanton coal units are converted to natural gas-fired power plants. OUC will be required to retire the Stanton A and Stanton B natural-gas-fired combined cycle by 2050 to meet its Net Zero CO_2 goal by 2050. This means that by the end of the forecast, the only fossil fuel units that remain in operation are the Indian River gas peaker units and the converted Stanton 1 and Stanton 2 units. OUC's portion of St. Lucie (60MW nuclear) and the landfill gas PPA's remain operational as well. Exhibit 16 shows a detailed portfolio build-out graphic for the 2020-2030 timeframe and a high-level overview of the capacity changes thereafter for the Gas Conversion 2026/2029 Portfolio.

Exhibit 16: Gas Conversion 2026/2029 Portfolio Build-Out (2020-2050)



Source: Siemens PTI

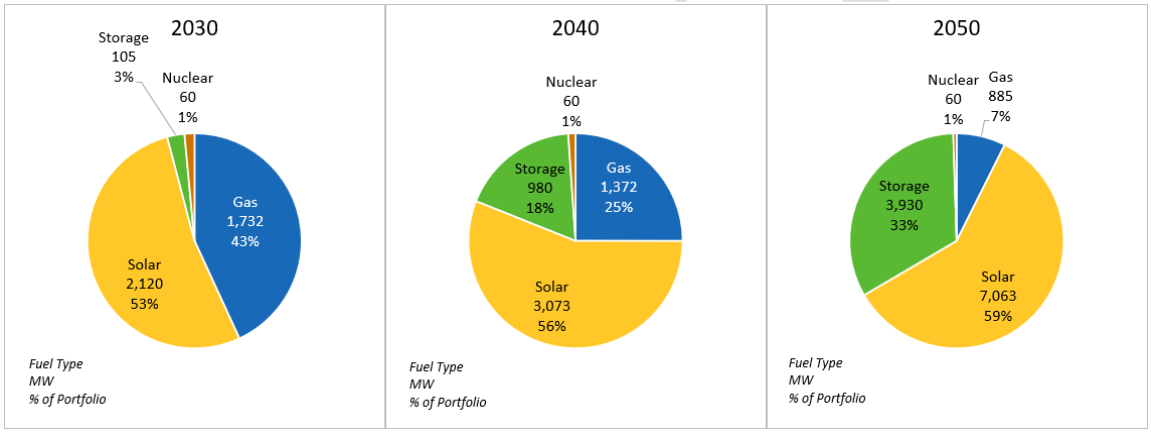
Similar to the Net Zero CO_2 by 2050 Portfolio, the Gas Conversion 2026/2029 Portfolio is allowed to maintain some fossil-fuel fired capacity, as long as the emissions from these resources remain below the levels allowed through the CO_2 offsets. Regardless of the flexibility, this portfolio has a relatively low diversity throughout the forecast (Exhibit 17). In 2030, the resource diversity is low, with 96% of the capacity installed as solar and gas-fired resources. This portfolio can maintain a relatively low storage capacity in 2030 because the converted units can act as fast-ramping resources and serve load in hours when solar is unavailable. In 2040, more storage capacity is added

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

due to a combination of the loss of the Stanton A PPA and an increase in load compared to 2030. This results in a more diverse resource mix compared to 2030, although solar remains the dominating resource. Ultimately, in 2050, the gas capacity is reduced even further to meet the 2050 Net Zero CO_2 target and is replaced with storage and solar capacity.

The overall capacity additions within this portfolio per technology are: 7,335 MW solar, 3,390 MW storage, and 693 MW natural gas-fired capacity. The retirements within this portfolio per technology are: 108 MW solar (PPAs and contracts), 880 MW gas-fired (Stanton A PPA and OUC's share of Stanton A and B), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 17: Gas Conversion 2026/2029 Portfolio Installed Capacity



Source: Siemens PTI

2.3.7 Gas Conversion 2036/2040

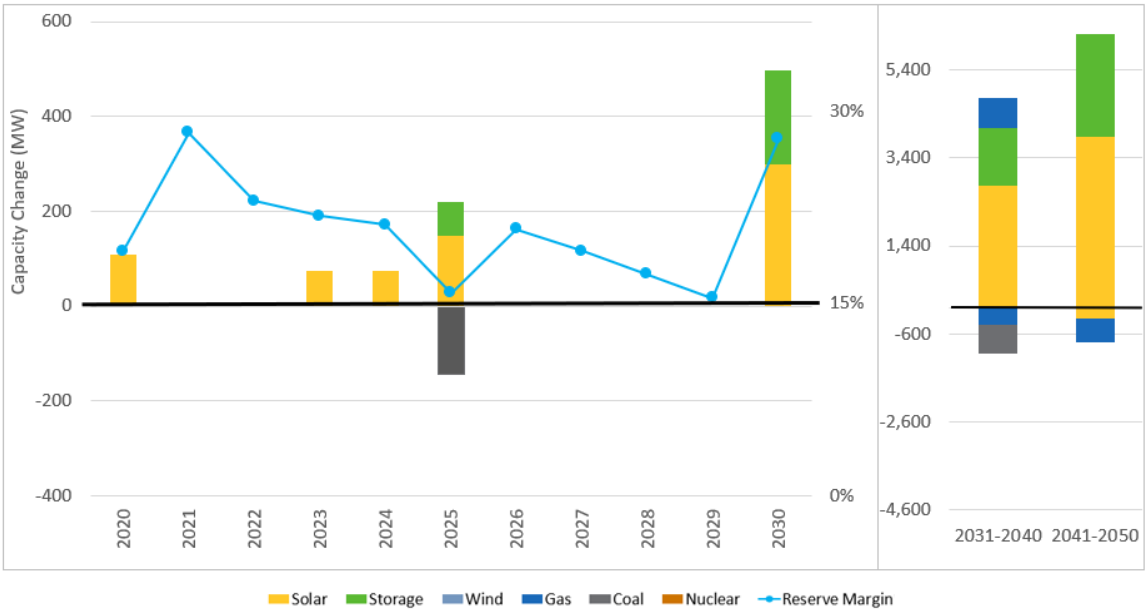
This portfolio is similar to the Gas Conversion 2026/2029 Portfolio in many ways. It converts the Stanton coal units to use natural gas as its main fuel but pushes the conversion of these units back to 2036 and 2040. Since this portfolio maintains the coal-fired capacity of Stanton 1 and 2 through the early 2030s, it runs a higher risk of violating the emission reduction targets, especially the 2030 target.

Because this portfolio follows the same logic as the Gas Conversion 2026/2029 Portfolio, Siemens PTI observes an identical capacity build out by the end of 2050. The main difference observed between the two gas conversion portfolios, is the timing of the solar and storage builds.

Exhibit 18 shows the detailed portfolio build-out of the Gas Conversion 2036/2040 Portfolio for the 2020-2030 timeframe, as well as a high-level view on the capacity changes for 2030-2050.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 18: Gas Conversion 2036/2040 Portfolio Build-Out (2020-2050)

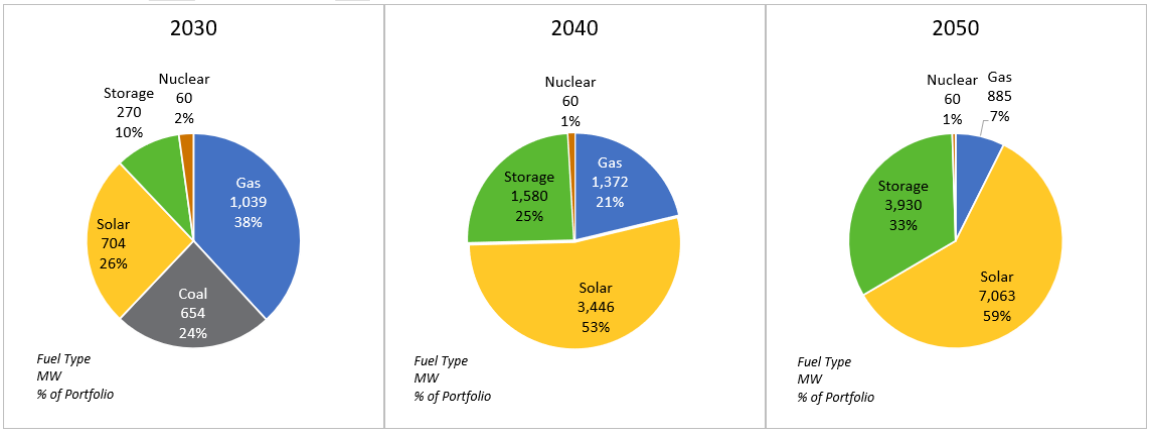


Source: Siemens PTI

Shown in Exhibit 19, this portfolio maintains a diverse portfolio in 2030 because the coal units are not converted. Most of the capacity in 2040 consists of solar and storage and a greater amount of these resources are installed compared to the Gas Conversion 2026/2029 Portfolio. To meet the 2050 100% Net Zero CO_2 target, this portfolio retires the Stanton A and B units by 2050. By 2050, the technology mix is identical to the Gas Conversion 2026/2029 Portfolio.

The installed capacity per resources is: 7,335 MW solar, 3,390 MW storage, and 693 MW gas-fired. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 880 MW gas-fired (Stanton A PPA and OUC's share of Stanton A and B), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Exhibit 19: Gas Conversion 2036/2040 Portfolio Installed Capacity



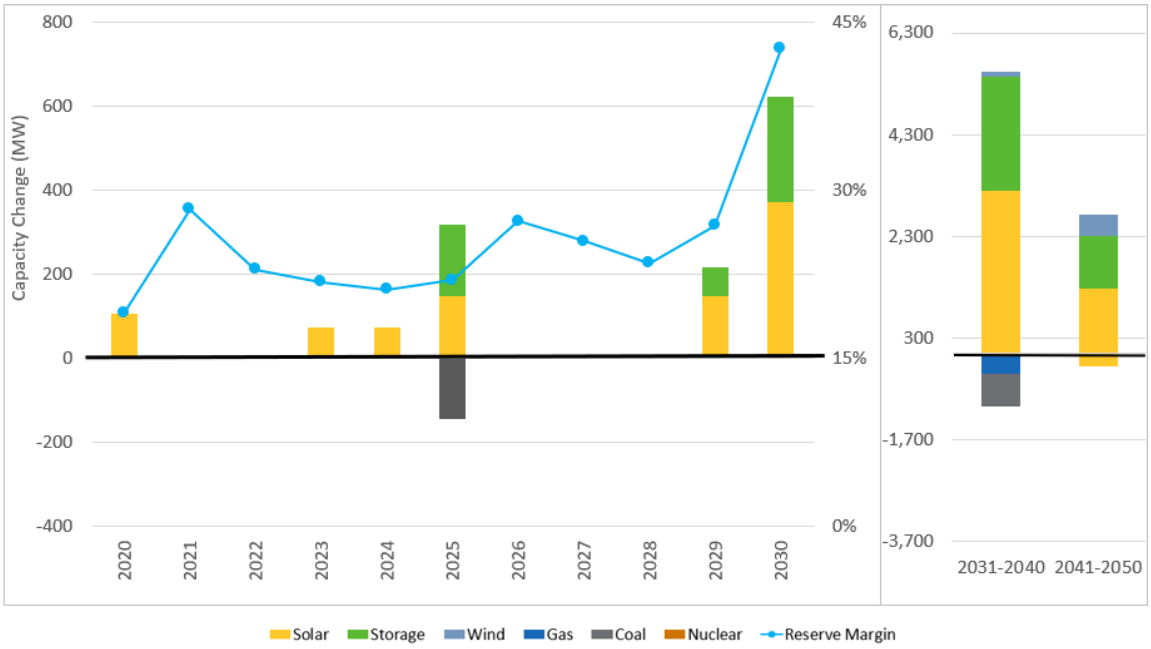
Source: Siemens PTI

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

2.3.8 Wind-by-Wire

The Wind-by-Wire Portfolio retires the Stanton 1 and Stanton 2 coal units by 2036 and 2040. However, this portfolio allows for replacing the fossil units with solar and storage, as well as the potential for wind-by-wire from the SERC region. The addition of wind capacity provides a resource with the ability to generate electricity when solar energy is unavailable. By adding the wind resource, less solar is required, and the reserve margin is reduced significantly compared to the Net Zero CO_2 by 2050 Portfolio. This portfolio shows the benefits of decreasing the reliance on solar and storage to back-fill the loss of fossil fuel capacity. Exhibit 20 shows a detailed portfolio build-out for the 2020-2030 time frame, as well as a high level overview of capacity changes in 2030-2050 for the Wind-by-Wire Portfolio.

Exhibit 20: Wind-by-Wire Portfolio Build-Out (2020-2050)

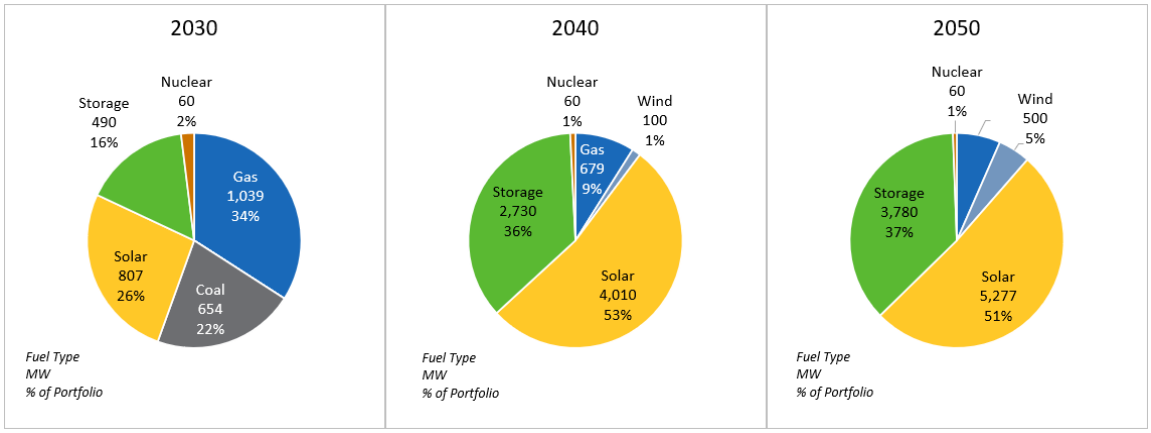


Source: Siemens PTI

Since the coal units are retired in 2036 and 2040, this portfolio observes a balanced resource diversity in 2030, shown in Exhibit 21. By 2040, the coal units are retired and most of the capacity installed is solar and battery storage. Additionally, 100 MW of wind capacity is brought in from the SERC region to partially replace the capacity lost from the coal unit retirements. By 2050, 500 MW of wind capacity is brought in from the SERC region to improve the resource diversity of this portfolio. The installed capacity per resource over the forecast horizon is: 5,398 MW solar, 3,780 MW storage, and 500 MW wind. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 21: Wind-by-Wire Portfolio Installed Capacity



Source: Siemens PTI

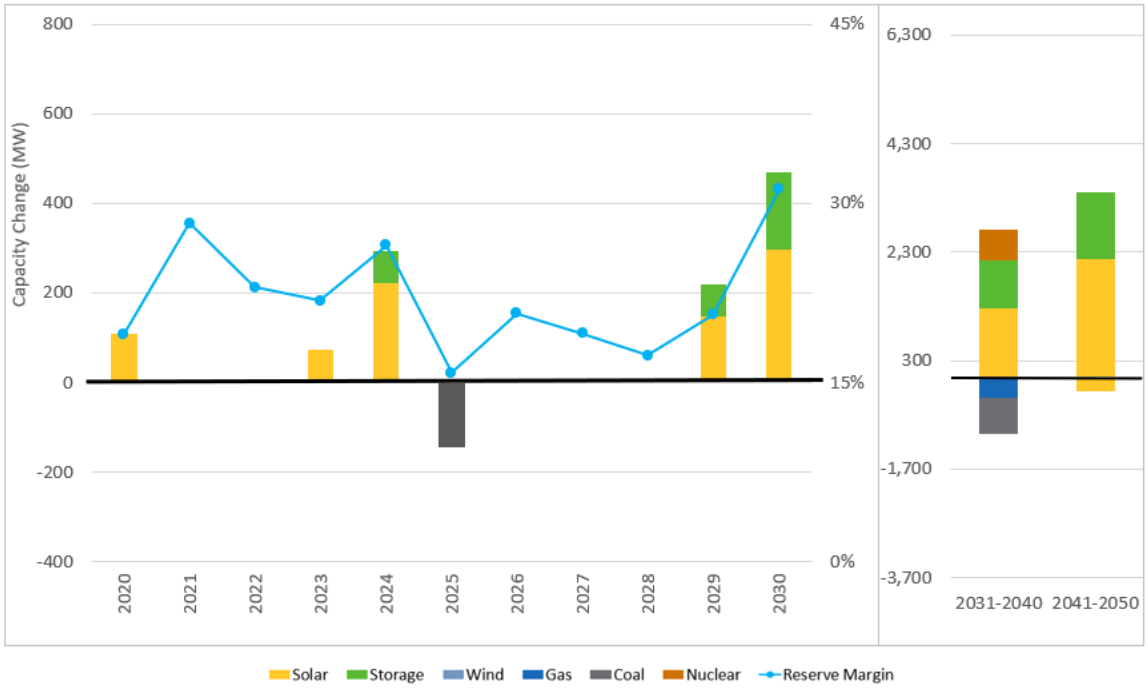
2.3.9 Modular Nuclear

The Modular Nuclear Portfolio retires the Stanton 1 and Stanton 2 coal units by 2036 and 2040. However, this portfolio allows for replacing the fossil units with solar and storage, as well as adding a small modular nuclear reactor (SMR) (for more details about SMR, see Section 5.2.6). Specifically, a 570 MW SMR unit is installed in 2036, essentially replacing the capacity lost from the retirement of the Stanton 1 and 2 coal units. Adding this dispatchable non-CO_2 emitting resource significantly decreases the solar and storage capacity required to serve OUC's load while still meeting the Net Zero CO_2 targets. Furthermore, this results in the Modular Nuclear Portfolio requiring the least amount of solar and storage builds, out of all Candidate Portfolios. Exhibit 22 shows a detailed portfolio build-out for the whole forecast horizon.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 22: Modular Nuclear Portfolio Build-Out (2020-2050)



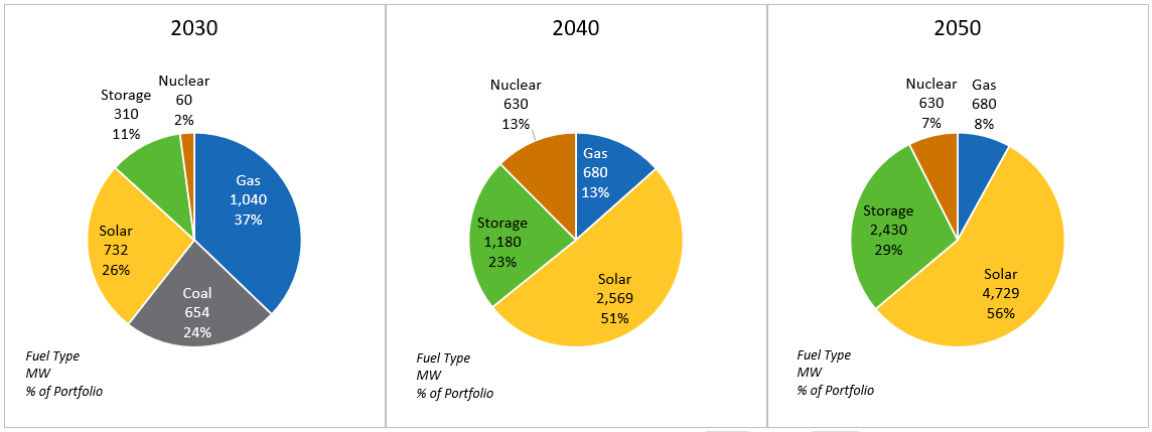
Source: Siemens PTI

Shown in Exhibit 23, this portfolio has a very similar capacity build out compared to some of the other Candidate Portfolios and maintains a well-balanced resource diversity, using coal, gas, solar, storage, and nuclear in 2030. By 2040, the Stanton 1 and 2 coal units are retired and replaced by the SMR reactor. Although the coal units are retired, the resource diversity in this portfolio remains fairly balanced, with solar making up half the capacity installed while storage, nuclear, and gas-fired capacity evenly splitting up the other half of installed capacity. By 2050, a little more than half of the capacity installed is solar, but the technology resource diversity remains more balanced compared to some of the other Candidate Portfolios. The installed capacity per resource over the forecast horizon is: 5,398 MW solar, 3,780 MW storage, and 500 MW wind. The retirements within this portfolio are: 108 MW solar (PPAs and contracts), 360 MW gas-fired (Stanton A PPA), and 801 MW coal (OUC's portion of CD McIntosh and Stanton 1 and 2).

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 23: Modular Nuclear Portfolio Installed Capacity



Source: Siemens PTI

2.4 Attributes and Metrics

As previously mentioned, the key Attributes considered in this EIRP are Reliability, Affordability, Sustainability, and Resiliency. Since these Attributes are somewhat competitive in nature, it is important to establish different metrics to measure the performance across these Attributes to properly analyze the performance of each portfolio on these Attributes. The metrics established for analyzing these Attributes are further described below.

2.4.1 Reliability

The Advisory Council determined that Reliability is the most important Attribute and weighted highest across the four Attributes. Consequently, each Candidate Portfolio was designed to be self-sufficient and able to serve all of OUC's load throughout the forecast period without relying on purchases from neighboring utilities *under expected conditions*. To distinguish the degree of Reliability between each Candidate Portfolio, two metrics are used for the Reliability Attribute.

Cloud Cover Analysis

Siemens PTI developed an analysis to determine the first year the portfolio could have insufficient energy during a period of very high cloud cover. Specifically, the cloud cover analysis degraded the solar output by 70%. This analysis evaluates the total generating capacity in each hour of the test period to determine if a shortage of capacity exists in any hour with solar output reduced by 70%. The first year of the forecast period where there is insufficient energy in any hour to meet demand is identified.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Technology Diversity 2050

The second metric established for the Reliability Attribute is the technology diversity at the end of the forecast. This metric was chosen because, in general, a system is expected to be more reliable if it has a greater number of generating technologies.

2.4.2 Affordability

The Advisory Council deemed the Affordability Attribute to be the second most important Attribute. For the Affordability Attribute, there are two metrics considered: the mean present value of portfolio costs and the uncertainty of those costs. Two periods are considered for each of these metrics. The first ten years, and the entire forecast period.

Present Value of Costs

The present value is the value of future portfolio costs discounted to 2020 based on a 6.3% discount rate, which is a weighted average between OUC's debt and equity percentages. This considers the time value of money; the generally accepted financial theory that near-term cash flows have greater value than future cash flows.

Uncertainty of Costs

The second metric for the Affordability Attribute is the uncertainty around the present value of costs. Since the stochastic analysis (further discussed in Section 7) provides a broad range of market outcomes, cost uncertainty can be measured as the standard deviation of costs over that range. The standard deviation measures the amount of dispersion of costs over that range over the forecast period.

2.4.3 Sustainability

The Sustainability Attribute was voted as the third most important by the Advisory Council. Metrics associate with the Sustainability Attribute calculate the probability of meeting Net Zero CO_2 targets as well as the clean energy percentage in 2050.

Probability of Meeting Net Zero CO_2 Targets

Through the stochastic analysis, Siemens PTI measured the likelihood that each Candidate Portfolio would achieve the Net Zero CO_2 targets. The portfolios with the highest probability of meeting the target in 2030, 2040 and 2050 score the best across these metrics.

Clean Energy Generation in 2050

This metric is calculated as a percentage of clean generation compared to the overall generation within the portfolio in 2050. Clean energy is defined as either a renewable resource (solar or wind), nuclear energy, or generation coming from landfill gas.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted
DRAFT

2.4.4 Resiliency

Metrics for the Resiliency Attribute measure the amount of unserved energy during the highest two-week load period in August of 2025, 2035, and 2045, during stressed conditions. The low probability, high outcome events that were used to test each Candidate Portfolio's Resiliency are described below.

East Coast Hurricane Scenario

This scenario is developed to represent how OUC is affected when a major hurricane hits the East coast of Florida. In this scenario, the hurricane causes multiple fossil-fuel powered plants to shut down to prevent catastrophically damage as well as a decrease in solar output. The effect of the hurricane scenario on the OUC plants is shown in

Exhibit 24. The red in the table on the left means that all OUC plants in that technology category are taken offline according to the percentages described in the table on the right. The black color in the table to the left means that there is no technology available in the portfolio during that year. The green color means that the technology in this year is not affected by the hurricane scenario. Additionally, the following powerplants are taken offline in areas outside of OUC: Sanford, Cape Canaveral, St. Lucie.

Exhibit 24: East Coast Hurricane Methodology[9]

OUC Units Only		Calibration	Net Zero CO_2 by 2050	100% Renewable by 2050	Coal Retirement 2022/2026	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Wind-by-Wire	Modular Nuclear	OUC Optimized Portfolio
Gas	2025									
	2035									
	2045			●*						
Conv.	2025									
	2035									
	2045									
Nuclear	2025									
	2035									
	2045									
Coal	2025									
	2035									
	2045									
Wind	2025									
	2035									
	2045									

Technology	1st Week	2nd Week
Gas	100% offline	50% offline
Conv.	50% offline	25% offline
Nuclear	100% offline	50% offline
Coal	50% offline	25% offline
Wind	n/a	n/a
Solar	75% offline	50% offline
Storage	n/a	n/a

Source: Siemens PTI

West Coast Hurricane

This scenario is similar to the East Coast Hurricane scenario since it observes a hurricane that hits the West Coast of the Florida peninsula. Since OUC is located closer to the East

[9] The black dot in the table to the right indicates that in the 100% Renewable by 2050 retires a Stanton gas-fired unit by 2044 so it already has less gas capacity around in 2045 compared to the other portfolios.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

side of Florida, this scenario has less of an impact on the OUC plants. Because of this, all the colors in the table on the left in

Exhibit 25 are green, meaning that the plants within that technology remain operating as they would under normal conditions. There is an assumption made about the effect the hurricane has on solar output and is reduced according to the table on the right. However, there are more plants affected in the rest of Florida. The Florida plants affected by this hurricane scenario are Hines Energy Complex, Bayside, Intercession, Anclote, P L Bartow, Larsen, Cane Island, Manatee, Tiger Bay, Big Bend.

Technology	1st Week	2nd Week
Gas	n/a	n/a
Conv.	n/a	n/a
Nuclear	n/a	n/a
Coal	n/a	n/a

Technology	1st Week	2nd Week
Gas	n/a	n/a
Conv.	n/a	n/a
Nuclear	n/a	n/a
Coal	n/a	n/a
Wind	n/a	n/a
Solar	75% offline	50% offline
Storage	n/a	n/a

Exhibit 25: West Coast Hurricane Methodology

Source: Siemens PTI

Gas Pipeline Disruption

This disruption scenario calculates the impact on OUC if a major gas pipeline is shut down, preventing natural gas from being delivered to gas plants throughout the Florida peninsula. Since this disruption scenario only affects the gas-fired plants, the only technologies affected in the OUC territory, presented in red in the table on the right in

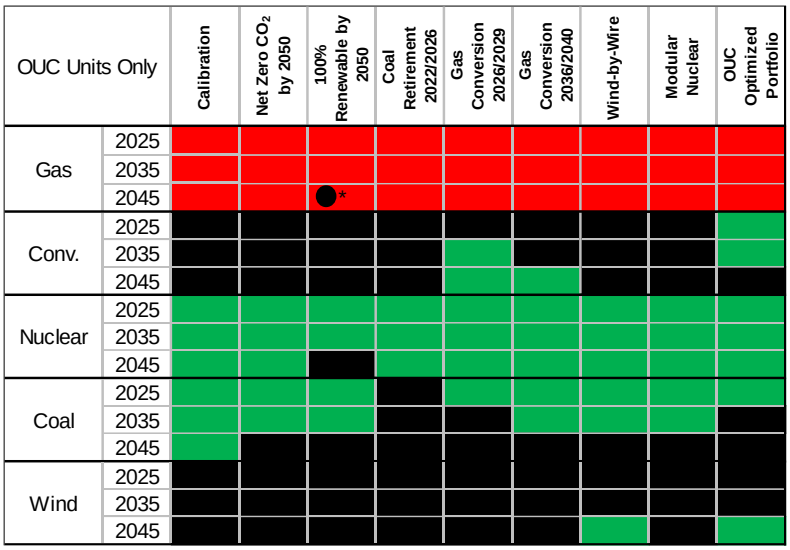
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 26 are the Stanton A and B combined-cycles, the Indian River A, B, C, D gas peakers, and the Stanton 1 and 2 gas conversions. The offline schedule during the two-week period is described in the table on the left. Furthermore, the gas-fired power plants affected in the Florida peninsula are: Shady Hills, Bayside, P L Bartow, Vandolah, Polk, Richard J Midulla, Osprey, Cane Island, Manatee, Hardee, Hines Energy Complex, Larsen, Intercession, Big Bend, Anclote, Higgins, Treasure Coast.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 26: Gas Pipeline Disruption Methodology



Technology	1st Week	2nd Week
Gas	100% offline	50% offline
Conv.	100% offline	50% offline
Nuclear	n/a	n/a
Coal	n/a	n/a
Wind	n/a	n/a
Solar	n/a	n/a
Storage	n/a	n/a

Source: Siemens PTI

DRAFT

Unrestricted
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

3. Load Forecast

OUC develops a base load forecast annually for its service territory. Included in this OUC forecast are assumptions for current economic projections, energy efficiency (EE), technology advancement, and codes and standards changes resulting in an OUC base net energy for load forecast. The latest OUC load forecast was used as a starting point for this EIRP. Presented here is an EIRP net load forecast through 2050 which is the OUC gross load forecast refined for energy efficiency, distributed solar generation (DG), and electric vehicles (EV), collectively load modifiers. These refined load modifiers are further described below. Siemens PTI also developed a stochastic load forecast around the refined net load forecast.[10]

3.1 Load Forecasting Methodology

The net load forecast was received from OUC for the 2020 to 2035 study period. Beyond 2035, Siemens PTI extrapolated OUC load to 2050. Net load modifiers from the original load forecast were deducted, or added to, the net load forecast to calculate a base load forecast. Siemens PTI developed average and peak load forecasts for each of these load variables as explained below.

3.1.1 Energy Efficiency Impact

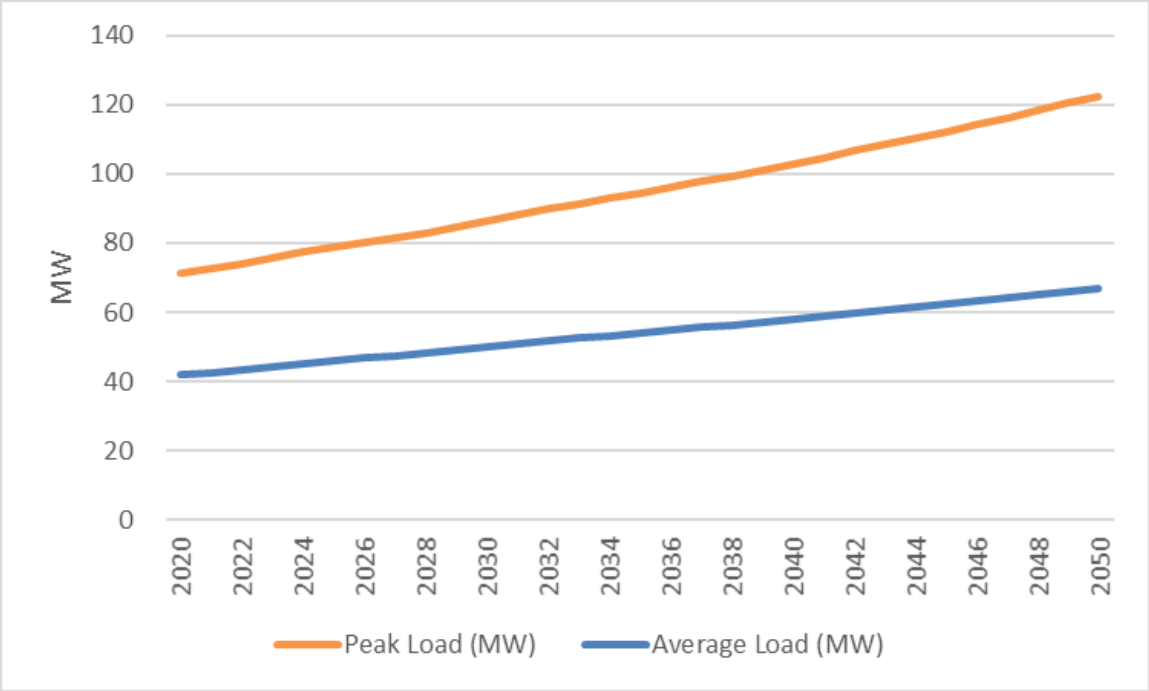
Energy efficiency refers to using technology that requires less energy to perform the same function. It includes the improvements in federal and state codes and standards that reduce energy consumption. In the EIRP analysis to measure Affordability and Sustainability for each portfolio, Siemens PTI reviewed all of OUC's energy efficiency plans and concluded that 0.5% incremental reduction per year is a reasonable expectation for energy efficiency load reduction. This 0.5% reduction per year exceeds the requirements of the Florida Public Service Commission (FPSC)[11]. In this EIRP analysis, Siemens PTI has included achieving the 0.5% load reduction in the base load forecast throughout 2050. Additionally, by using a broad range of potential future demand over the forecast horizon (2020 – 2050), Siemens PTI allowed for a high degree of potential energy efficiency penetration.

DRAFT

[10] Load forecast is based on information available as of Q1 2019.
[11] FPSC's goal is approximately 0.1% of sales through 2024.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 27: Annual Average and Peak Load EE Reduction Estimates



Source: Siemens PTI

3.1.2 Distributed Generation (DG) Impact

Distributed generation, primarily rooftop solar, is treated in Siemens PTI's analysis as a decrement to energy consumption. Siemens PTI's expected value assumptions on rooftop solar penetration were based on an independent distributed solar adoption study from the National Renewable Energy Laboratory (NREL). Peak impact is assumed to be half of the adoption nameplate capacity.

3.1.3 Electric Vehicle (EV) Impact

Siemens PTI forecasted the net energy for load and peak load impacts of increased electric vehicle adoption within OUC's service territory through the forecast period. To estimate the potential for EV adoption in OUC's territory, Siemens PTI applied a proprietary electric vehicle forecasting approach, which employs Siemens PTI's market view, a leading Light Duty Vehicle (LDV) adoption tool, and Siemens PTI's proprietary analytical models to project commercial vehicle adoption and load calculations.

The Siemens PTI's expected LDV adoption forecast leverages proprietary inputs and adjustments to the latest version of the best-in-class customer choice model (MA^{3}T Model[12]) developed by Oak Ridge National Labs (ORNL). This model generates forecasts for both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) by state. Siemens PTI segmented the Florida forecast derived from this model into OUC's LDV portion using OUC's residential customer count. The commercial vehicle base

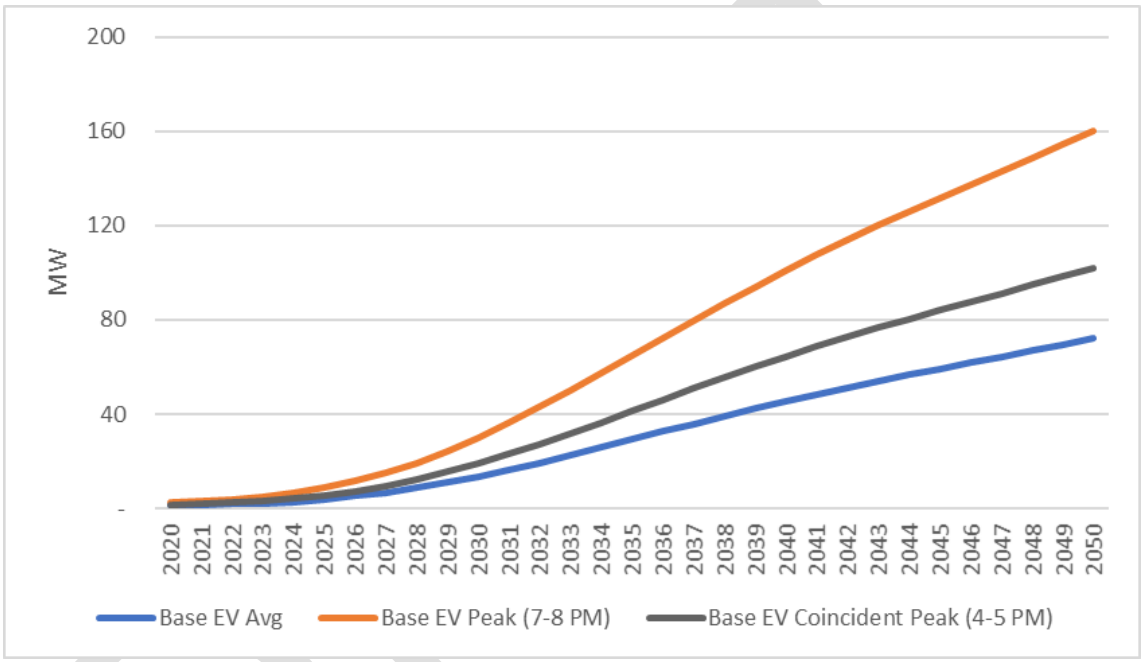
[12] https://www.ornl.gov/content/ma3t-model

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

forecast was derived from the Department of Energy's 2019 Annual Energy Outlook EV adoption forecast, which we applied to the commercial vehicles operating in OUC's service territory.

As illustrated in Exhibit 28, average load and peak load impacts from electric vehicle charging are very small in 2020, but rise gradually over the period of the analysis. Electric vehicle charging activity usually peaks at 7-8 PM, which does not currently coincide with the summer peak hour of the OUC system at 4-5 PM. Therefore, the charging impact on the system's coincident peak is lower than the maximum charging impact. The charging impact on average load is lower than the peak.

Exhibit 28: Electric Vehicle Average and Peak Load Impact



Source: Siemens PTI

3.1.4 Demand Response

Demand Response includes programs that provide incentives for specific customer classes to reduce energy consumption during high demand period. Siemens PTI reviewed several studies, including the market potential study from Nexant from April 2019, sponsored by the seven electric utilities (FEECA Utilities[13]) subject to Florida Energy Efficiency and Conservation Act, which assessed Demand Response (DR) potential based on an analysis of mass market direct load control programs.

These studies include residential, small commercial and industrial (C&I), as well as analysis of DR programs for large C&I customers. The large C&I programs assessment

[13] FEECA Utilities include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC) and JEA.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

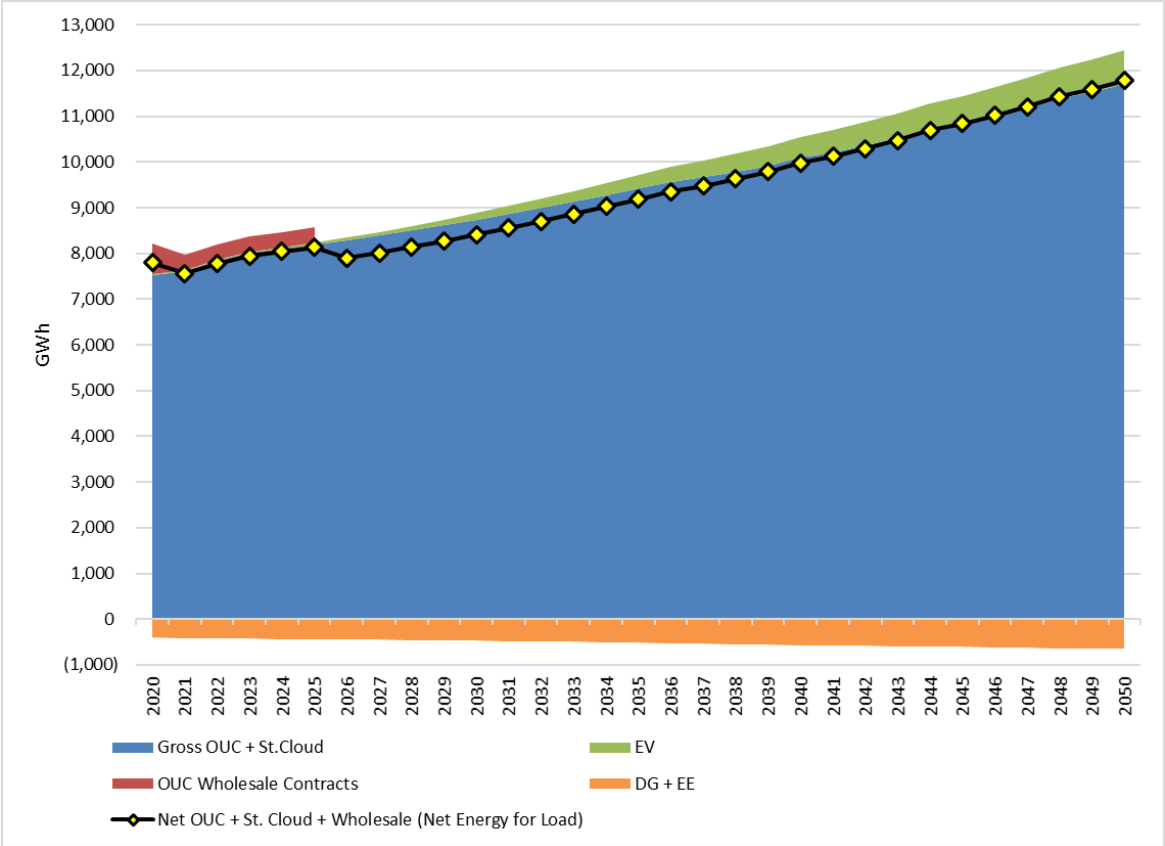
used publicly available data on mature DR programs to derive estimate of price responsiveness to program incentives and market techniques. The analysis is focused on potential for demand reduction through air conditioning, central heating, ventilation, water heating, and pool pump load control. These were chosen in part because of their large contribution to peak period system load.

Siemens PTI concluded that demand response penetration and cost would not result in a meaningful reduction in demand based on the current state of demand response programs and customer usage profiles. However, as is the case with energy efficiency and other load modifiers, Siemens PTI incorporated a broad range of energy demand levels to test the portfolios. This approach allowed for the potential for a much greater penetration of demand response and other load modifiers.

3.2 Long-Term Net Energy and Demand Forecast

The long-term net energy base forecast estimates are presented below in Exhibit 29 and peak load in Exhibit 30. This net energy forecast is the gross system energy forecast after accounting for separate forecasts of all load modifier impacts. The forecast includes an overall increase in energy consumption over the 2020-2050 period. The net annual average growth rate is about 1.6% for net energy for load and peak load.

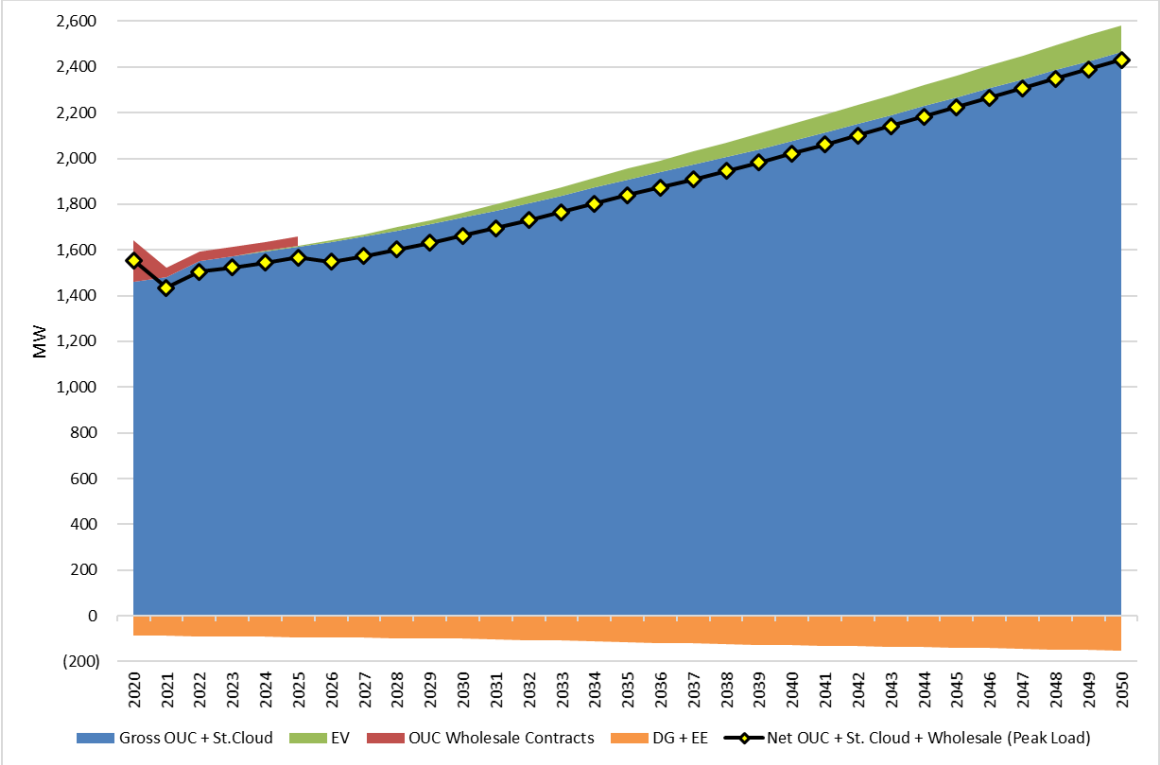
Exhibit 29: Forecasted Net Energy Estimates (GWh)



Source: Siemens PTI

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 30: Forecasted Net Peak Load (MW)



Source: Siemens PTI

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

4. Environmental Considerations

This EIRP analysis serves as a means for OUC to determine how to meet all of OUC's load over the 31-year forecast horizon. However, an additional motive for this EIRP analysis was to align with the City of Orlando's target of 100% renewable energy by 2050. To do this, OUC established the goal of Net Zero Carbon by 2050. To provide a consistent path toward achieving this goal, OUC also established some interim Net Zero CO_2 goals. In 2030, OUC aims to reduce CO_2 emission by 50% compared to 2005 levels and by 2040 the reduction is aimed to be 75% reduced compared to 2005 levels. This section will outline some of the underlying environmental considerations implemented in this EIRP analysis.

4.1 CO_2 Pricing

No comprehensive national regulation of CO_2 emissions currently exists in the U.S. in spite of efforts to enact policies covering CO_2 emissions from major sources. This included efforts by the U.S. Congress to pass a national cap and trade regime, the EPA's regulation of greenhouse gas emissions from new and existing power generators, and more recently, proposals in Congress for CO_2 taxes and comprehensive clean energy targets.

Action to limit CO_2 emissions has increased recently with states taking the lead in defining low- and no-CO_2 generation requirements. Currently, Florida does not have a state policy covering CO_2 emissions from power generation. To account for the uncertainty of potential federal CO_2 legislation, an expected price on CO_2 emissions from fossil generators is assumed (Exhibit 31). This outlook includes a national CO_2 price to become effective in 2025 and rising each year thereafter, covering emissions from electric generating units in the U.S.

Exhibit 31: Expected Value CO_2 Price Projections (2019$/ton CO_2)

Year	2020	2025	2030	2035	2040	2045	2050
CO_2 Price	$0	$6	$11	$16	$30	$41	$45

Source: Siemens PTI

Candidate Portfolios were designed to meet 2050 CO_2 limitations and then tested for compliance as part of the Sustainability Attribute. Specifically, each portfolio was structured to meet the Net Zero CO_2 targets under expected conditions with OUC modeled as an isolated system. The costs of CO_2 did not serve as an economic driver during the development of the portfolios. There was no price for CO_2 assumed during the development of Candidate Portfolios, but CO_2 costs were used to measure the performance of the Candidate Portfolios.

As presented in later sections of this report, a range of possible future CO_2 costs were included in the study and are contained in the Affordability Attribute metric for each portfolio. The

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

range of CO_2 prices used in the analysis allows for the high degree of uncertainty in potential federal climate change regulations and legislation.

4.2 Electric Vehicles used for CO2 Offsets

To assist with meeting Net Zero CO_2 targets, electricity producers are assumed to have available CO_2 offsets. The Environmental Protection Agency defines a CO_2 offset as "a specific activity or set of activities intended to reduce GHG emissions, increase the storage of CO_2, or enhance GHG removals from the atmosphere"[14]. These offsets can be used for both direct and indirect emissions from an electricity producer's operations.

There are many ways in which electricity producers can use CO_2 offsets but for the purpose of this analysis the only offset considered is increased electric vehicle adaptation. The idea is that by increasing the number of electric vehicles on the road and replacing internal combustion vehicles, the CO_2 emissions avoided from the use of electric vehicles can offset the CO_2 emissions originating from electricity production. This allows for CO_2 emissions above the original emission target to allow for more flexibility on fossil-fuel generation. This flexibility provides the potential to reduce the costs by reducing the required resource capacity build-out to meet OUC's, while maintain the ability to meet the emission reduction targets.

DRAFT

[14] For a detailed explanation of offsets, please refer to https://www.epa.gov/sites/production/files/2018-03/documents/gpp_guide_recs_offsets.pdf

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

5. Resource Options

This section documents the methodology Siemens PTI applied to develop the cost and performance assumptions for all new-build generation and energy storage technologies for OUC, as well as assumptions on existing unit optimization (i.e., coal-to-natural gas conversions). These assumptions are used to develop the portfolios, for measuring performance regarding the four key Attributes, and are summarized by resource type (new generation, conversion, storage).

5.1 New Generation and Energy Storage Resources

Siemens PTI maintains a technology cost and performance database that includes all applicable studies, projects, and announcements from over fifty public and confidential client sources. All sources in the database are maintained to be within three years of the current year to sustain up-to-date assumptions. Key public sources include annual reports such as the NREL Annual Technology Baseline (ATB), the EIA Annual Energy Outlook (AEO), the Lazard Levelized Cost of Energy, and the Lazard Levelized Cost of Storage. In addition, key subscription sources such as ThermoFlow, S&P Global, Energy Velocity, and Greentech Media are included.

Siemens PTI screens each source for equipment type, model, project scope, and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Siemens PTI then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology.

The technology database provides the foundation for our technology cost and performance forecasts. To develop longer term cost projections, Siemens PTI considers several factors, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. By varying assumptions (i.e. productivity, learning curves, technology obsolescence, cost escalations etc.), Siemens PTI develops a distribution of values for each technology over time, which we apply to define high and low values for each of the technologies.

Other technologies that are not currently commercially available such as hydrogen, fuel cells and tidal energy are not included in the study. OUC will continue to monitor these technologies and consider them in future EIRPs.

5.2 Assumptions

For this analysis, generation options for the portfolios including advanced combined cycle gas turbine (CCGT), conventional CCGT with duct firing, simple cycle advanced frame combustion turbine (CT), simple cycle aero derivative CT, single-axis tracking solar PV (either self-build or PPA), wind-by-wire (with firm transmission rights from SERC), lithium-ion battery storage, onshore wind (for new-build resources in the SERC market), and nuclear small modular reactor

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

(SMR), are explained in more detail in the following section. The underlying detailed assumptions are included in Appendix A.

5.2.1 Combined Cycle Gas Turbine

Combined cycle gas turbines (CCGTs) provide a reliable source of capacity and energy for relatively low plant capital investment. Relatively fast ramp rates and the ability to cycle daily allow CCGTs to integrate with the variable nature of renewable generation.

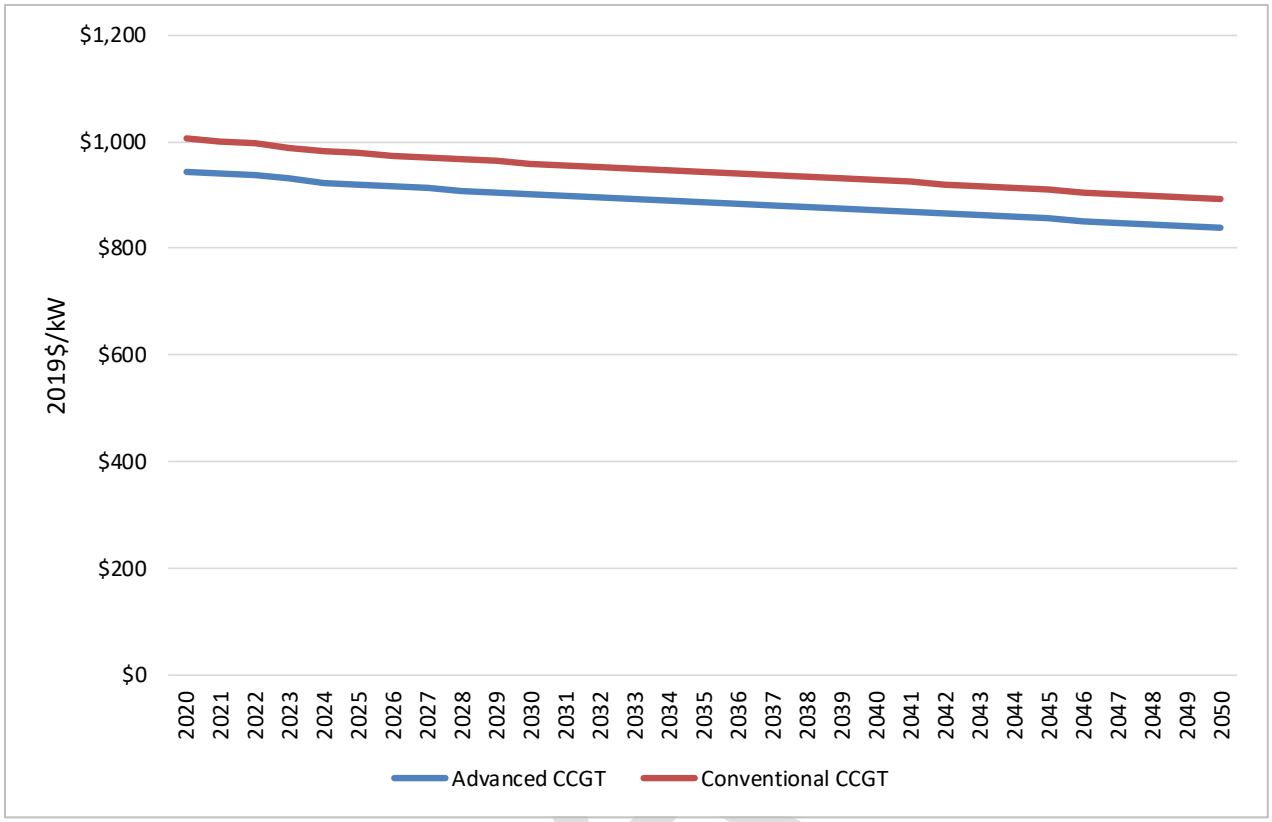
Advanced CCGTs can achieve operating efficiencies above 62%, compared to conventional generation technologies (including simple cycle CTs) that range from 30 to 44%. Generally, CCGTs are good replacement options for less efficient, higher-emitting fossil fuel resources. Favorable capital costs, operational flexibility, lower CO2 emissions, and high plant efficiencies have allowed CCGTs to expand their role in power generation, serving as either baseload or intermediate, load-following generators.

Advanced CCGTs in a 2x1 configuration (950 MWs) generally offer the lowest cost of generation and in large markets, are often selected for their competitive costs. While these units are large, they represent a small portion of generation in a large market, so the impacts on Reliability of a forced outage are manageable. However, the Reliability impacts of a forced outage for this unit operating in the FMPP pool would be very challenging. OUC's peak load is expected to reach more than 2,250 MW and such a unit would represent 42% of that peak demand. As a result, Siemens PTI considered smaller 1x1 CCGT configurations including one at 605 MW and another at 385 MW. Siemens PTI optimized the 1x1 CCGT by adding duct firing (i.e. adding burners in the heat recovery steam generator [HRSG] to produce more steam). If a CCGT was selected as part of a long-term capacity expansion plan, the duct firing portion would increase the unit capacity Reliability support at a lower capital cost and better heat rate than a simple cycle gas turbine.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 32: Combined Cycle Capital Cost Forecast, 2019$/kW



Source: Siemens PTI

5.2.2 Simple Cycle Combustion Turbine

The high operating costs and low efficiency of simple cycle combustion turbines (CT) (around 40%) typically keep annual capacity factors below 10% and limit CTs primary use to load peaking purposes. However, CTs start quickly and ramp up and down quickly, and play a key role in grid stability, providing reserve capacity and ancillary services. The responsiveness of CTs make them viable candidates to manage intermittent resources such as renewables on a broad scale. Historically, frame CTs were used as peaking resources because of their low operating costs and economies of scale, and aero derivative CTs were also used for peaking service when smaller capacities were a better fit. Newer frame CT models offer higher capacities (300 to 400 MW) and increased efficiency (heat rates of 8,000 to 8,500 Btu/kWh) than earlier models. Aero derivative CTs are available in relatively small capacities with heat rates between 8,000 to 10,500 Btu/kWh, albeit with higher unit costs.

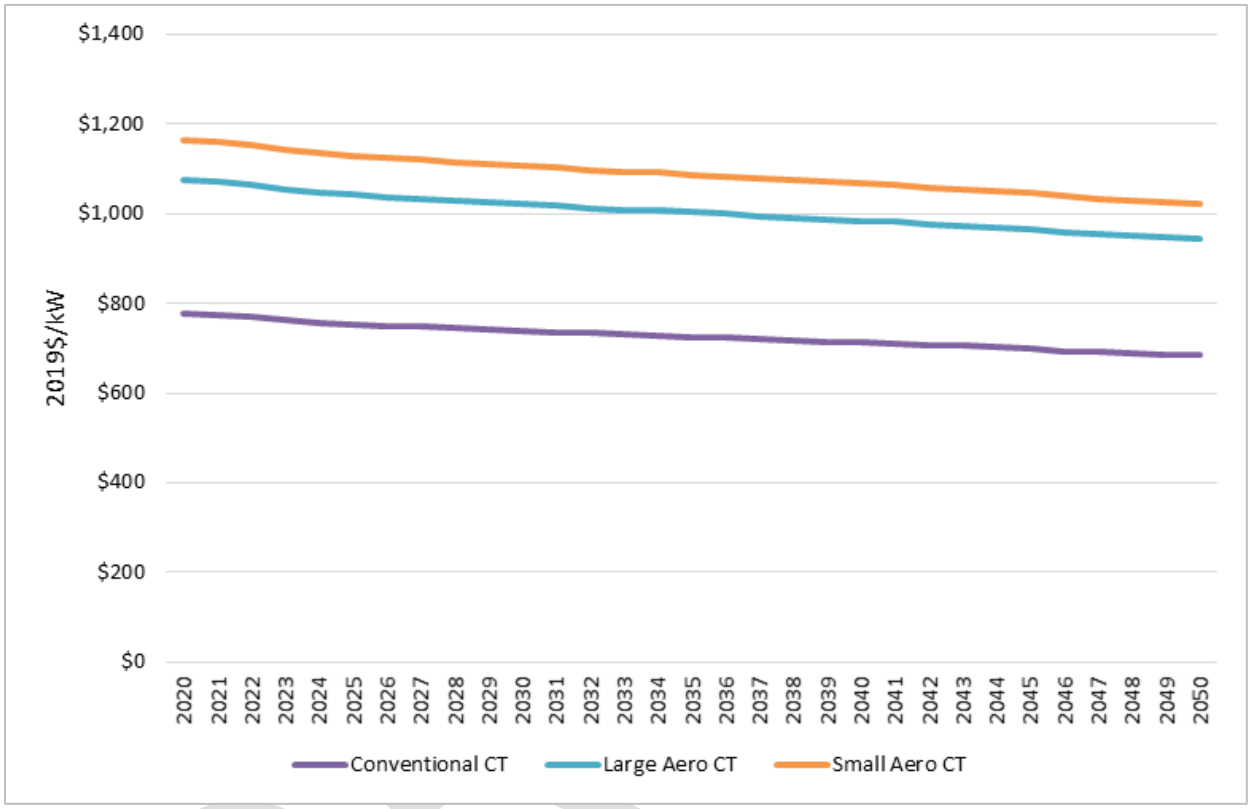
An influx of intermittent energy resources and lower load growth, as well as the need for more flexible resources has increased interest in aero derivative CT technologies to provide faster ramping capabilities. Newer models provide faster start up, higher ramp rates, and integration with other technologies, particularly battery energy storage.

Siemens PTI compared its simple cycle combustion turbine capital cost assumptions to both NREL ATB and EIA AEO similar technologies, as it does with most technologies, and determined

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

prices to be in broad alignment. It is important to note that NREL does not disclose the size or type (frame vs. aero) of their combustion turbine assumptions in the ATB, so a direct comparison can be difficult. For reference, Siemens PTI presents our forecast for conventional frame (7FA technology) and advanced frame below.

Exhibit 33: Simple Cycle CT Capital Cost Forecast, 2019$/kW



Source: Siemens PTI

5.2.3 Battery Storage

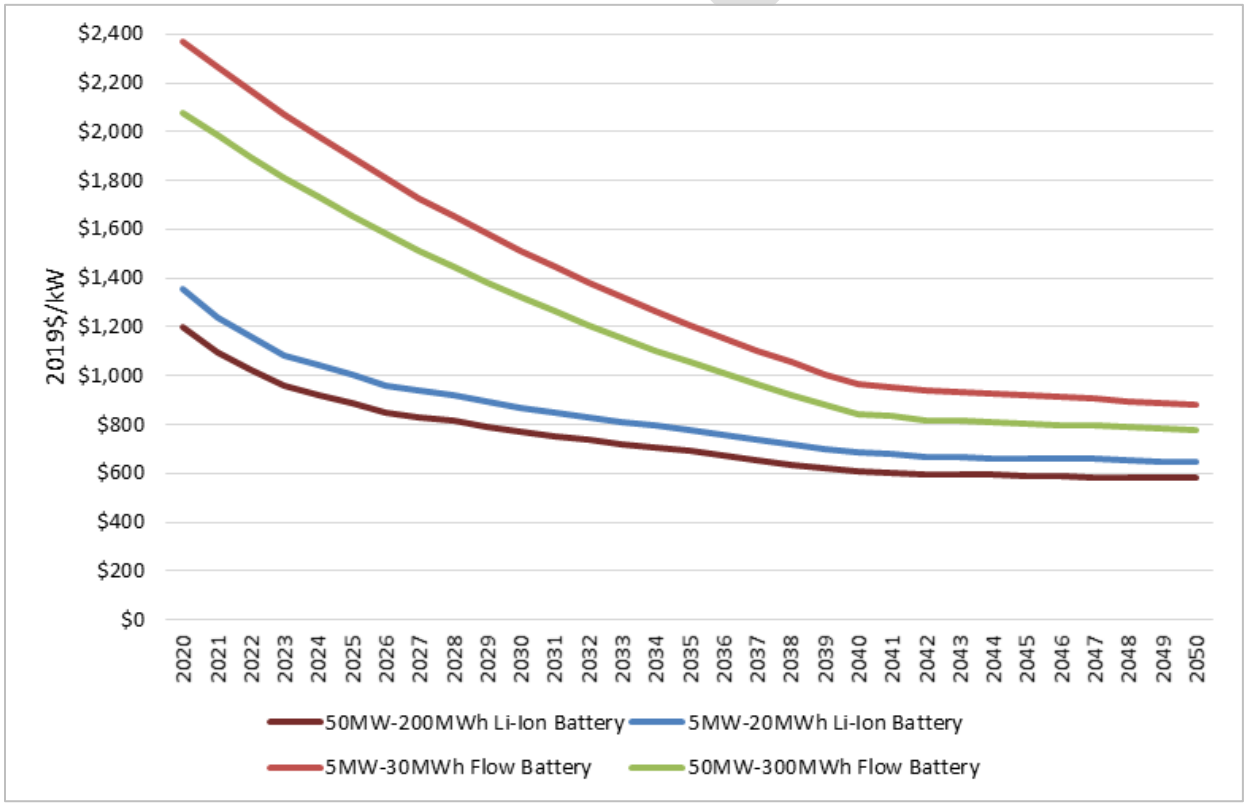
In recent years, battery energy storage has become more important as a utility-scale option to integrate non-dispatchable resources onto the energy grid. Lithium-ion (Li-ion) batteries are the most common type of storage used at the utility scale and can target location-specific applications unsuitable to pumped hydro or compressed air energy storage. Other storage technologies beginning to be considered for broad use include various flow battery chemistries, thermal storage (either high or low temperature), hydrogen storage, and other fuels created from hydrogen including ammonia and synthetic methane. Li-ion battery costs are declining as suppliers increase production and as the technology matures, making them a popular choice for current energy storage needs. Manufacturing capacity is expected to grow to meet strong energy storage demand from mobile devices, medical devices, and electric vehicles. Currently, there are no significant supply constraints observed but there are concerns over the availability of lithium at current prices.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

The battery storage sector has experienced strong growth in recent years. Between 2011 and 2018 there were 810 MW of power capacity from large-scale battery storage added leaving a total of 869 MW battery storage power capacity operational by the end of 201815. Most of existing U.S. power capacity has been installed by independent power producers (IPP) in the PJM Interconnection (PJM). Regulated utilities in the California Independent System Operator (CAISO) territory have procured storage capacity as well. The United States observed a new record for annual power capacity additions in 2018 when it saw 222 MW of large-scale battery storage installed.

Li-ion batteries have accounted for 94% of all new energy storage capacity in the U.S. since 2012, growing at an average rate of 55% per year. Most of the installed Li-ion capacity provides frequency regulation, but recent projects in the U.S. have targeted alternative applications including peaking capacity, renewable integration (energy arbitrage), peak shaving, shifting, smoothing, firming, and other use cases. Exhibit 34 presents Siemens PTI's battery storage capital costs.

Exhibit 34: Battery Storage Capital Cost Forecast, 2019$/kW



Source: Siemens PTI

An important consideration for battery storage is that there are efficiency losses from storing the energy and dispatching it later. Each time energy is stored in the battery, 85%-90% of it

[15] U.S. EIA, Battery Storage in the United States: An Update on Market Trends, July 2020: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

will be able to be dispatched with the remaining percentage lost in the process. The efficiency losses increase over the time that the battery is in operation.

A key challenge of battery storage technology is capacity degradation. With every battery cycle (i.e. charging and discharging the battery fully), the ability of the battery to retain charge is diminished. After 10 years the capacity of a battery storage project may decline by 15 to 20%. For an owner wishing to maintain the capacity of a battery system over time, battery capacity must be augmented with replacement capacity under the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application.

Siemens PTI expects that OUC would elect to maintain the capacity of any battery system installed and would need to account for the augmentation costs. Siemens PTI assumed augmentation of the battery packs every seven years, with battery packs comprising approximately 40% of the cost of the total battery system. In total, the battery augmentation cost is about 13% of the total battery system cost. Each battery storage system's capacity is replaced at the end of its operational life of 20 years (also its book life), keeping the system capacity the same but at the current year replacement cost.

5.2.4 Solar Photovoltaics (PV)

Solar PV generation has been expanding as a form of renewable generation in recent years, with total U.S. installed capacity reaching 81.4 GW through Q1 2020.16 Single-axis tracking solar PV systems offer higher capacity factors and require less land for nearly the same unit cost as fixed-tilt systems. As a result, tracking solar installations now account for more than 50% of utility-scale solar PV in the U.S. and are most common in the southwest.

Renewable energy incentives have played a critical role in supporting the development of solar PV, either in the form of Renewable Portfolio Standards (RPS), feed-in tariffs, or tax credits. The Investment Tax Credit (ITC) is set to decline to 10% of capital investment in 2022, remaining available post-2021. Developers can "safe harbor" solar equipment for up to four years to qualify for the ITC, past the deadline.17

Siemens PTI's single-axis tracking solar technology forecast accounts for the increasing application of bifacial solar cells. While monofacial cells dominate the market today, bifacial cells are expected to comprise most solar cells sold by 2030. While bifacial cells cost slightly more than monofacial cells, they can deliver small but meaningful generation gains over monofacial cells, so Siemens PTI's forecast accounts for a phasing in of bifacial technology. Exhibit 35 shows Siemens PTI's forecast for solar PV.

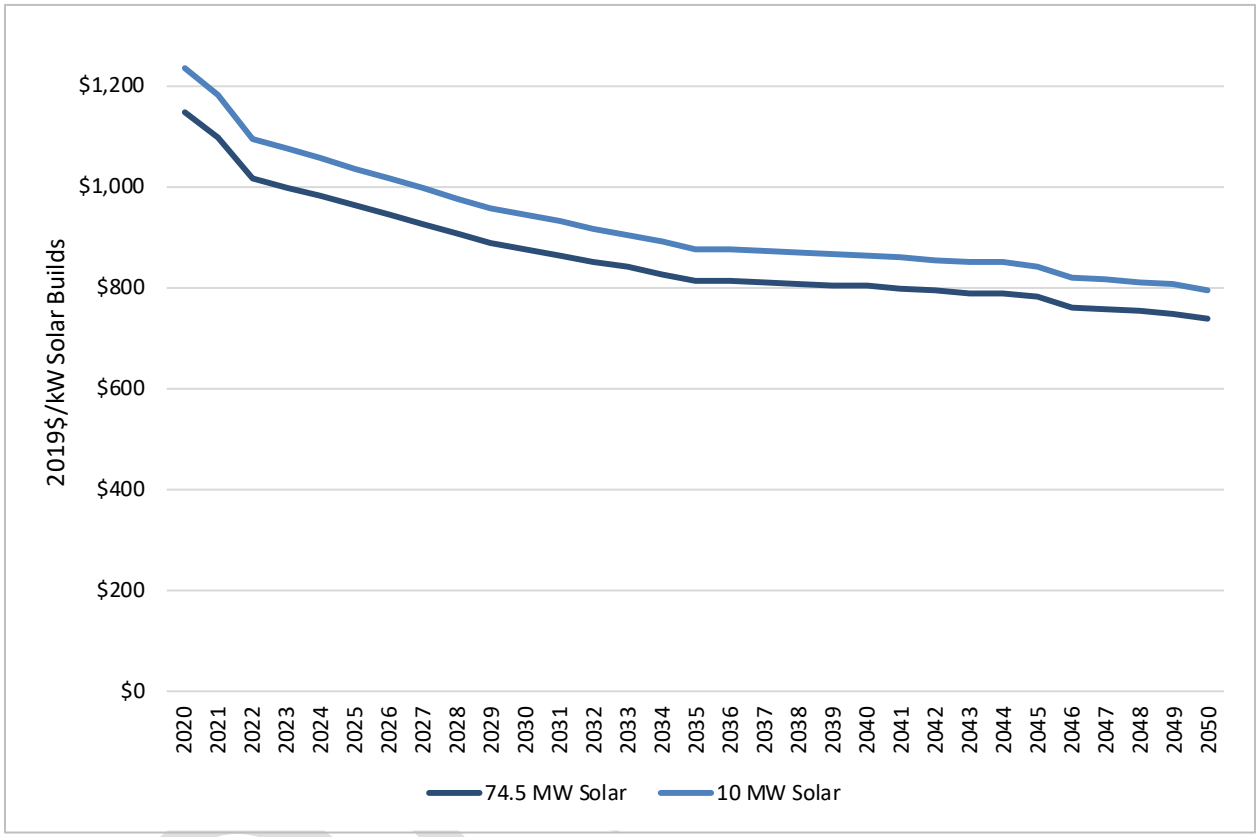
OUC considered both generic solar builds (which could be self-build, developer turn-key, or some other commercial arrangement) and solar PPA purchases. The solar PPA purchase price

[16] SEIA U.S. Solar Market Insight: Q1 2020
[17] Siemens assumes two years of safe harboring in our calculations.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted
DRAFT

is benchmarked to recent offerings seen in the marketplace and conversations with solar developers. There are several moving parts to solar prices, including trade tariffs, the sunsetting ITC, land costs (see the following section), wheeling costs etc. These solar PPAs are limited based on geographical diversity of OUC's service territory.

Exhibit 35: Single-Axis Tracking Solar PV (2019$/kW)



Source: Siemens PTI

Land Consideration

One of the constraints associated with utility-scale solar PV development that should not be ignored is land availability and geographical diversity. Siemens PTI worked with OUC to identify local land considerations for utility-scale PV build in this EIRP. Greater geographical diversity of solar energy will be required to minimize the risk of cloud cover and other extreme weather events. The prospective land for solar PV is typically limited to agriculture and/or large commercial and industrial parcels that are generally flat, not prone to flooding, and relatively affordable. Current solar PV technology requires approximately 5 acres of land for every MW of capacity, i.e. a typical-for-Florida 74.5 MW PV project would require 373 acres of land. Further, solar developers try to select sites that are co-located next to existing transmission rights-of-way to minimize interconnection costs. Solar PV development in Central Florida will be hampered by the limited availability of attractive land and the likely need to acquire multiple conjoined parcels for larger capacity plants. Siemens PTI estimates that the largest portfolio solar PV buildout of 10,000 MW of solar PV capacity by 2050 would require 50,000

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

acres of land or, for scale and context, approximately 69% of the land area of the City of Orlando. The cost of land was also reviewed in collaboration with OUC for solar PV development in the Central Florida region. Considering the limited availability of suitable land, the cost of land is expected to be higher than the national average.

5.2.5 Onshore Wind and Wind-by-Wire

Wind generation is one of the largest source of CO_2-free electric generation in the United States, accounting for 7.3% of power produced in 2019[18] generated from 98,000 MW of installed wind capacity. Technology improvements coupled with lowered production costs have resulted in declining capital and operating costs, and improved performance resulting in increased unit energy output. In general, wind turbines are taller with larger wind-swept areas which allows them to produce more energy across a wider range of wind speeds, which drives up average capacity factors.[19] Further, the federal Production Tax Credit (PTC) has lowered recent prices for wind power. However, the PTC is scheduled to phase out by 2020, which could affect near-term Affordability for new wind resources. Developers can "safe harbor" wind turbine equipment for up to four years to qualify for the PTC past the deadline.

Siemens PTI allowed for onshore wind developed for the SERC region, with costs beginning at $1,542/kW (2019$) in 2020 and ending at $1,102/kW in 2050 (also in 2019$), as well as the wind-by-wire option for OUC. In the wind-by-wire option, the wind energy is assumed to come from the Midcontinent Independent System Operator, with the corresponding wind generation profile of that region. The wind-by-wire energy transactions would incur multiple wheeling charges going through 3 or more systems in order to deliver the energy to Orlando. The wind energy is benchmarked to recent market prices.

5.2.6 Small Modular Reactor (Nuclear)

Small modular reactor (SMR) technology was initially developed for naval/shipping purposes and is being adapted for utility scale generation. It has not yet demonstrated commercial operation in the United States, though a test is being conducted in Idaho. SMR modules range in size from 10 to 300 MW (compared to roughly 900 to 1,200 MW for conventional nuclear reactors), and modules can be scaled to meet loads. Some SMRs, by virtue of their smaller size and other operational features, can offer greater capability to conduct load following operations than larger nuclear power plants. SMRs have appeal as potential future CO_2-free reliable non-intermittent resources to complement renewable resources.

Much of the key equipment components for SMRs can be manufactured off-site in controlled factory environments, reducing plant construction time by an expected 40% or more. They also provide potential improvements in safety from their underground containment designs and passive cooling systems. However, underground installations could make maintenance more challenging during a malfunction. NuScale Power LLC is aiming to put an SMR into commercial operation in Idaho, comprised of a dozen 50 MW reactors. It is the only company

[18] https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

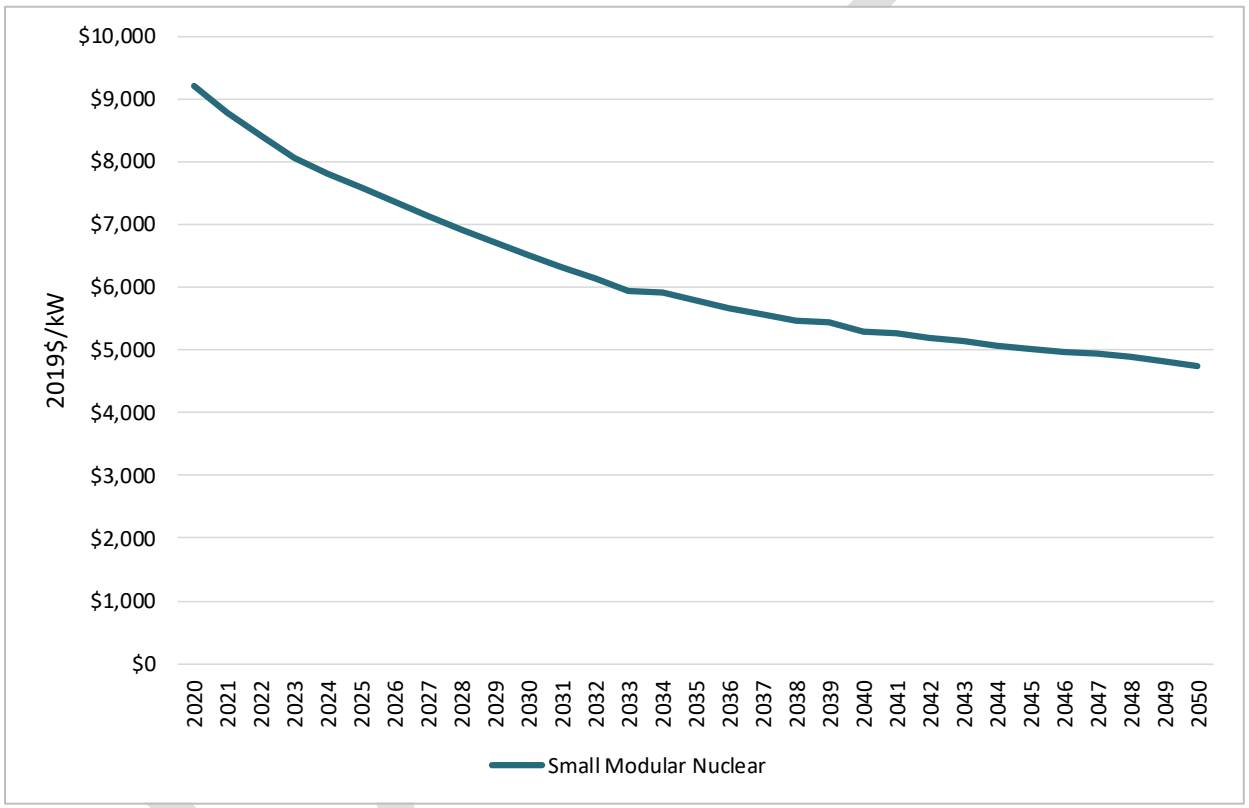
[19] Siemens PTI assumes wind generation can be built in the SERC region, but is not an option for the FRCC market.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

with an SMR design certification recently approved by the U.S. Nuclear Regulatory Commission (NRC). The NRC is also reviewing two SMR pre-applications from BWXT mPower, Inc. and SMR Inventec, LLC.

For this EIRP, an SMR was modeled at a capacity of 570 MW, which captures the economics of scale that would come with a larger SMR build but lower unit cost after incorporating the base costs that come with one module or 10 modules. The capital costs of SMRs are shown in Exhibit 36.

Exhibit 36: Small Modular Reactor (Nuclear) All-In Capital Cost, 2019$/kW



Source: Siemens PTI

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

6. Fuel Forecast

For the development of new supply options, several natural gas thermal units, including combined cycle gas turbines (CCGTs), combustion turbines (CTs), and conversion units were offered for the long-term capacity expansion optimization process used as part of the development of Candidate Portfolios. Natural gas price projections were also used to evaluate the costs to operate conversion units and existing gas-fired power plants. For the EIRP, Siemens PTI used gas price projections from PIRA.

6.1 U.S. Natural Gas Market Outlook

The U.S. natural gas market outlook is expected to see low prices at the benchmark natural gas commodity price at the Henry Hub market point in the short-term to 2021, despite increasing liquefied natural gas (LNG) demand and with higher storage refill requirements coming out of the 2018-19 and 2019-20 winters. Low prices are primarily due to excess production particularly with the ongoing natural gas production increases out of the Permian Basin and the Marcellus Shale. The main drivers of Henry Hub pricing in the short-term are:

1. The drop in natural gas demand due to shelter-in-place responses to the COVID-19 pandemic, counterbalanced by the decline in associated gas production due to low oil prices stemming from an oversupply in global crude oil markets.
2. LNG export demand, which is expected to grow from 4.5 billion cubic feet per day (Bcf/d) in 2019 to 9-10 Bcf/d by 2021 from online or under construction projects, out of a total LNG export capacity of 10.6 Bcf/d. Furthermore, there were three Gulf Coast LNG projects reaching a go-forward Final Investment Decision in 2019, which are expected to add an additional 4 Bcf/d of LNG export capacity in the early- to mid-2020s, for a total of 14.6 Bcf/d by 2024.
3. U.S. production growth, most of which is coming from the Marcellus Shale and Permian Basin, albeit to a lesser extent in the latter with a decline in oil prices (and thus associated gas production).
4. Over 43 Bcf/d of U.S. pipeline projects under construction or expected to become operational through 2021 (15.5 Bcf/d is Marcellus takeaway capacity and 8.6 Bcf/d is Permian takeaway capacity).

The 14.6 Bcf/d of LNG export capacity expected by 2024 is mostly under "take-or-pay" contracts, meaning demand for LNG feedstock gas will be baseload with liquefaction capacity expected to run at an 85% capacity factor or greater. LNG export demand is expected to put modest upward pressure on prices, despite low Asian LNG prices in early 2020. However, we expect that the downward price pressure from supply/production growth and pipelines will largely moderate any such increase in prices.

Generally, a trend has emerged of increased gas usage in the power sector at the expense of coal burn. With natural gas prices still relatively cheap compared to historical levels and coal

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

facing other economic and regulatory pressures, there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain power regions, particularly during shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, for example the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Annual electricity generation from coal declined 31% in the past decade (2009-2018) from 1,756 Terrawatt-hours (TWh) to 1,204 TWh, while generation from natural gas increased 43% from 921 TWh to 1,319 TWh, with natural gas surpassing coal beginning in 2016.

Major uncertainties on the demand side include the power sector response to new environmental regulations and rapidly declining renewables costs and battery storage costs that can displace gas-fired generation. While a CO_2 regime is not likely to advance in the current U.S. government administration, the finalized Affordable Clean Energy (ACE) rule has been promulgated and is expected to lead to heat rate improvements for coal plants >25 MW that will in turn lead to greater dispatch of coal units. Nevertheless, utilities and other generators are beginning to plan for the rising probability of a CO_2-constrained future.

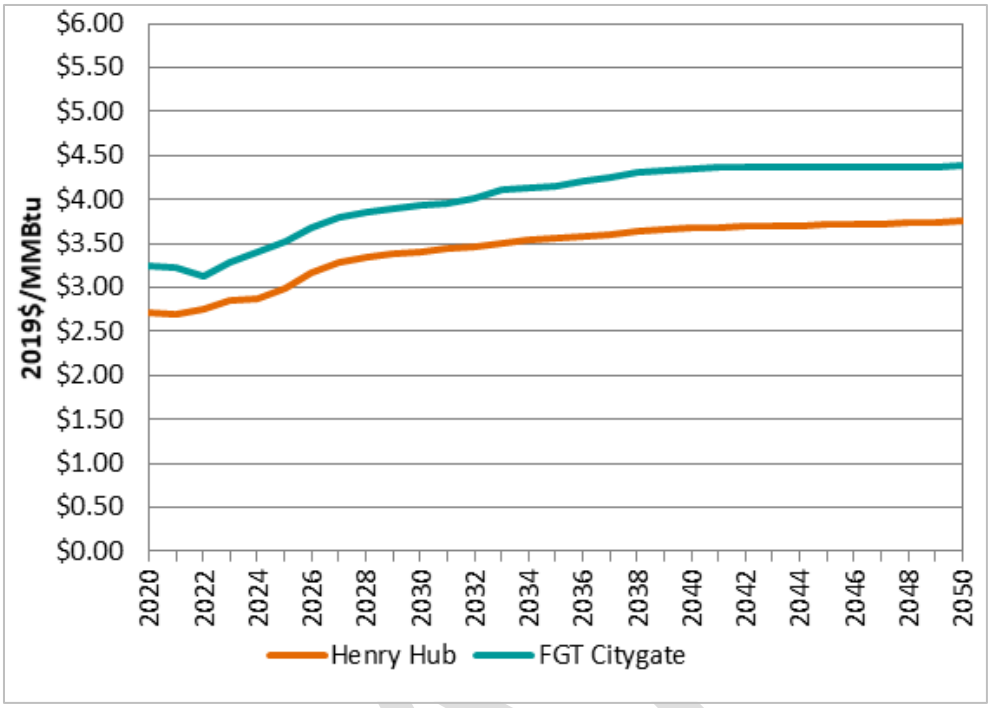
On the supply side, shale gas accounted for over 70% of U.S. gas production in 2018, up from 17% in 2008. During this time, unconventional gas production (primarily shale gas) has changed the perception of gas markets and has been the primary driver of Henry Hub pricing, causing prices to drop from the 2008 records that topped $13/MMBtu. The cost of production in 2019 ranges widely, from core Marcellus Shale play acreage able to generate breakeven returns at only $0.80/MMBtu compared to higher-cost conventional or non-core shale that might require prices of $4/MMBtu or more to break even. Additionally, U.S. gas production is influenced to a relatively substantial degree by oil prices. When oil prices are high, incentivizing producers to drill for oil and natural gas liquids, a significant amount of associated gas can be produced as a by-product. Associated gas now accounts for 20% of total U.S. production, with notable recent growth in associated gas in areas such as the Permian Basin in West Texas.

In addition, the nature of drilling in shale plays is that, while initial production can be strong, the production curve declines very rapidly. A sustained or growing level of production requires ongoing drilling programs. This has resulted in U.S. supply becoming more responsive to market conditions, with shale wells acting as virtual storage to adapt quickly to changes in the market. It also means that a decline in oil prices, as occurred in early 2020, can lead to a decline in associated gas production. Producers typically hedge a significant portion of their forward production, but a sustained decline in oil prices will result in less associated gas production growth out of regions such as the Permian Basin. Exhibit 37 shows increasing real prices over time as declining associated gas production is coupled with rising marginal costs of production and extraction.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 37: Annual Henry Hub Natural Gas Forecast (2019$/MMBtu)



Source: Siemens PTI and PIRA

The Stochastic section of this report presents Siemens PTI's view on possible ranges of future prices for natural gas under different views of regulations (e.g. fracking), markets (e.g. exports) and technology advance[20].

6.2 Natural Gas Forecast Methodology

The Gas Pipeline Competition Model (GPCM) was used to develop long-term price forecasts by incorporating the fundamental drivers of supply, demand, and infrastructure described in the prior section. In the short-term, natural gas forwards were averaged and used explicitly for the first 18 months of the forecast, after historical prices. In the subsequent 18 months, the forecast is blended away from forwards toward the fundamental GPCM forecast, after which the forecast is purely fundamentals-based. This provides a view of natural gas prices and basis to Henry Hub delivered to liquid market trading points throughout the United States. The price forecast does not include delivery from the market trading hub to each plant gate, as not all these transportation costs align with the published tariffs nor can it be certain which hub is indexed in each plant's supply contract.

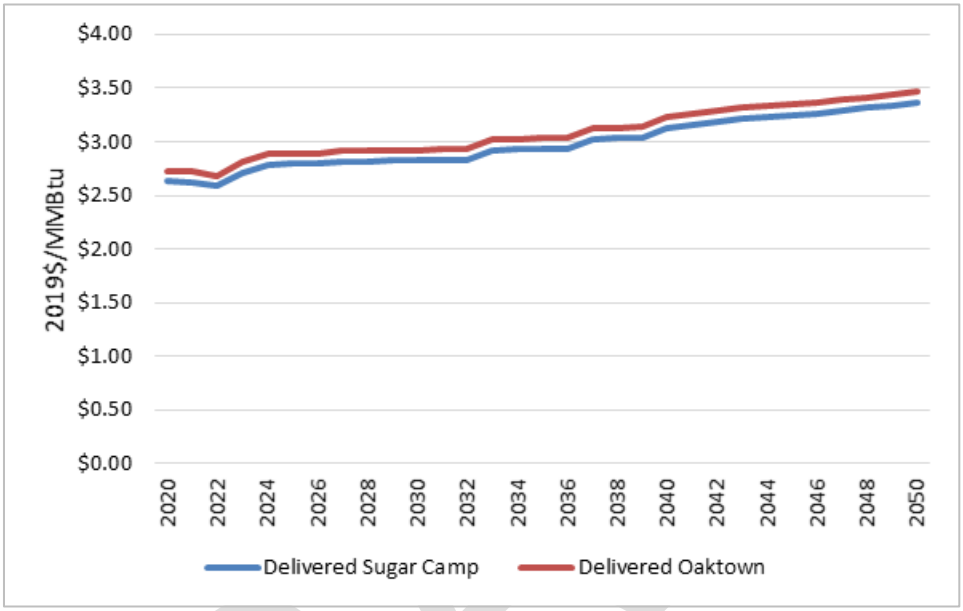
[20] The natural gas commodity price forecast used in this EIRP is based on information available as of Q1 2019 from PIRA.

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

6.3 Coal Price Forecast

Siemens PTI used Energy Ventures Analysis' coal price outlook for this EIRP analysis. This forecast for delivered OUC coal prices from two specific mines in the Illinois Basin is provided below for reference.

Exhibit 38: OUC Delivered Coal Price Outlook (2019$/MMBtu)



Source: Energy Ventures Analysis

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

7. Stochastic Analysis

7.1 Introduction

Probabilistic modeling (also known as stochastic analysis or risk analysis) incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for some of the metrics in the Balanced Scorecard.

Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, CO_2 prices, peak and average load (at the OUC, FMPP, FRCC, and SERC levels), and capital costs for a range of technologies. These 200 sets of future pathways are based on the forecasts of the expected value of these variables, described in Sections 3, 4, 5, and 6. These stochastic variables are initially forecasted for use over the study period, typically 1,000 to 3,000 times. A stratified sampling of the simulations is used, which then allows the sample set to be reduced to 200 iterations, or individual simulations, while still allowing for a representative sample of the universe of potential outcomes. These inputs allow for the testing of each portfolio's performance across a wide range of market conditions.

All Candidate Portfolios were subjected to each of the 200 iterations or simulations using the production cost model AURORAxmp in dispatch mode where the OUC portfolios are fixed but other FRCC and SERC members can make their own build and retirement decisions.

The stochastic modeling of each portfolio was developed by Siemens PTI using the AURORAxmp® dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, CO_2 prices, and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term, and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which simulated 200 possible future states over the 30-year study planning period.
- In the third step, each Candidate Portfolio was then run through simulated dispatch for the 200 possible future states using the AURORA production cost model. AURORA dispatches the Candidate Portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, AURORA assumes that each Candidate Portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. OUC generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for key metrics associated with the Attributes (Affordability, Sustainability) are tracked across all 200 iterations and presented as a distribution with a mean and other percentile (5^{th}, 25^{th}, 50^{th}, 75^{th}, and 95^{th}).
- These measures are used as the basis for evaluation in the stochastic analysis.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

7.2 Use of Stochastic Analysis

The stochastic analysis includes the probabilistic modeling conducted to inform the objective analytical considerations in the selection of the Leading Portfolio. Many other factors were considered besides the stochastic analysis. Nevertheless, a key part of designing the Leading Portfolio was based on how well each portfolio scored on multiple metrics and Attributes across 200 energy market simulations representing different, but internally consistent and plausible, market conditions. The selection process consisted of several comparisons illustrating each Candidate Portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The Leading Portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 simulations, while also maintaining Reliability and providing resource diversity/system flexibility. This procedure is used and presented in the sections below where each portfolio is assessed.

7.3 Stochastic Distributions

To perform the probabilistic modeling, a set of probability distributions was required for each of the key market driver variables (fuel, emissions, load, and capital costs). 200 future paths for each stochastic variable were developed using statistical methods. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in Appendix B: .

7.3.1 Load Distributions

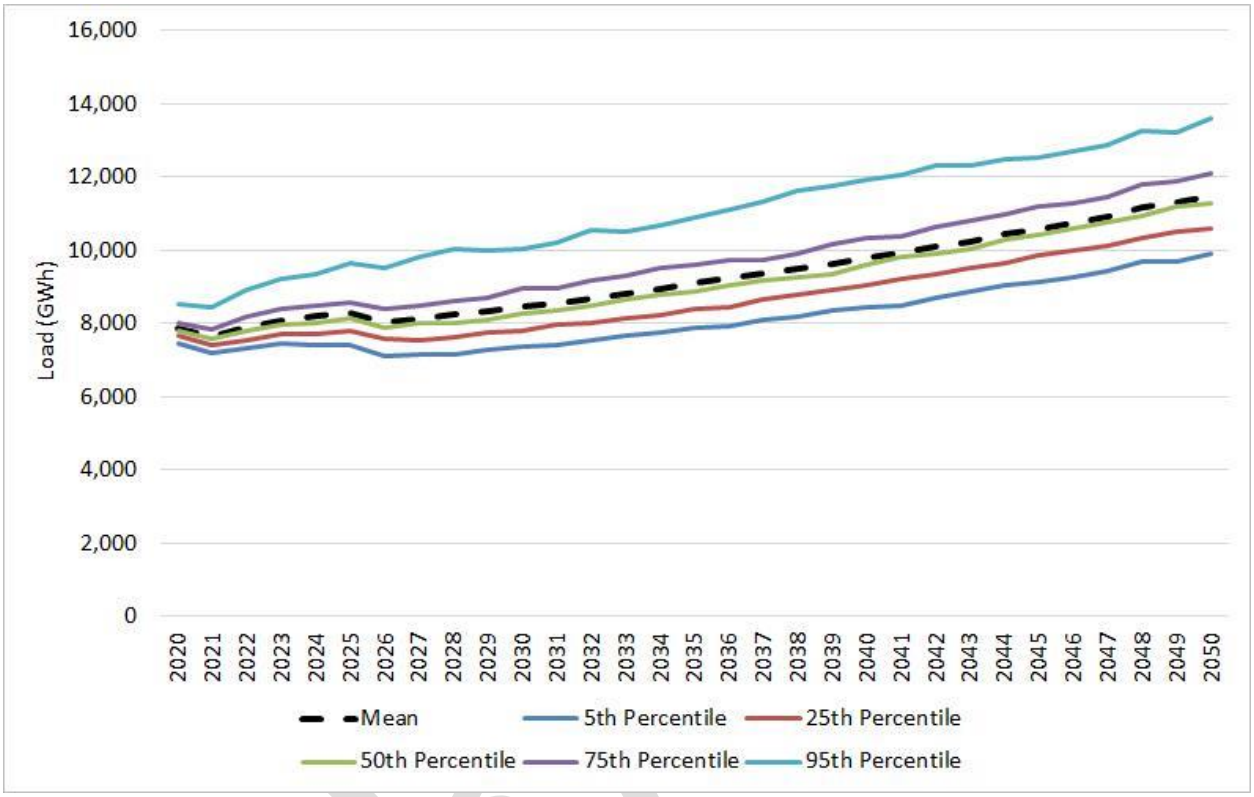
To account for electricity demand variability and uncertainty that derives from economic growth, weather, energy efficiency, distributed generation and demand side management measures, Siemens PTI developed a range of stochastic inputs around the energy demand expectations for the OUC service area and the neighboring markets including FMPP, FRCC, and SERC. The base long-term load forecast was provided by OUC with some extrapolation to 2050. For the broader FRCC and SERC markets, Siemens PTI forecasted long-term energy demand using a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the potential impacts of energy efficiency, demand response, distributed generation and electric vehicles.

Siemens PTI benchmarked the market-wide energy demand projections against FRCC- and SERC-sponsored load forecasting studies that are conducted by independent consultants, institutions, and market monitors to ensure consistency. Exhibit 39 shows Siemens PTI's stochastic range for energy demand and includes a wide range of potential energy efficiency, demand response, distributed generation and electric vehicle adoption. The stochastic distributions are the net result of 200 random simulations for the base net load forecasts. Siemens PTI calculated the distributions for the 5th and 95th percentiles (approximately two standard deviations), quartiles (25th, 50th, and 75th) percentiles, and the average (mean) of the annual distributions over time. Siemens PTI's Stochastics Methodology is further explained in Appendix B: .

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

As shown in Exhibit 39, the overall distribution shows a higher level of future load growth exceeding the expected value.

Exhibit 39: Forecasted Net Energy Load (GWh) Distribution[21]



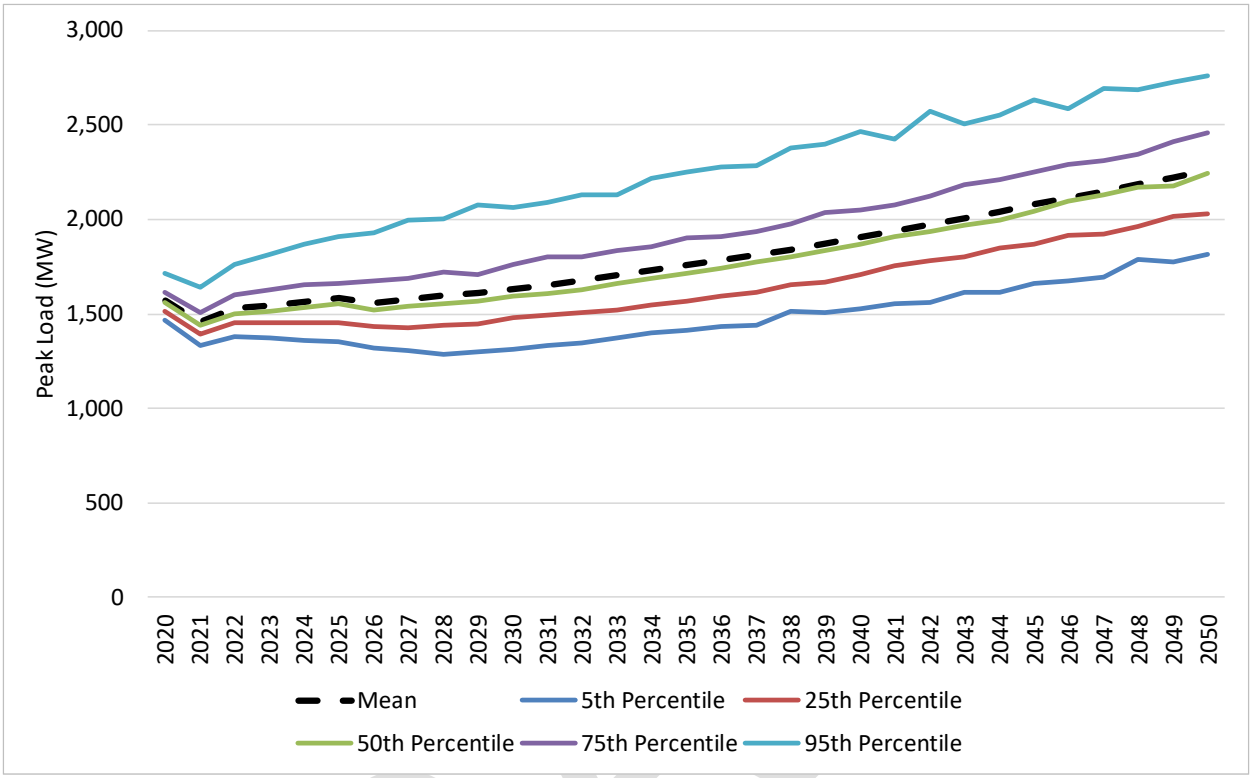
Source: Siemens PTI

Similarly, as shown in Exhibit 40, the stochastic distribution also shows a higher potential that peak load will exceed the mean or expected value over time. Both the forecast of total energy demand and the forecast for peak energy demand allow for a wide range of energy efficiency, demand response, distributed generation and electric vehicle adoption, all of which could reduce or increase the energy that would need to be generated and distributed by OUC. Energy efficiency, demand response, and distributed generation assist with reducing the energy required to meet load. Together, these resources have the potential to reduce the load by 6% in 2050 under base load forecast. Similarly, electric vehicles increase the net energy for load by 5% in 2050. Through the stochastic analysis the net energy required for load vary by a much wider range throughout the study period. For example, the 95th percentile is 18% higher than the base forecast, and the 5th percentile is 14% lower than the base forecast by 2050, which represents a wide range of potential load modifier penetration.

[21] Reductions in load in 2021 and 2026 are a result of the expiration of wholesale sale commitments.

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 40: Forecasted Peak Load (MW) Distribution[22]



Source: Siemens PTI

7.3.2 Natural Gas Price Distributions

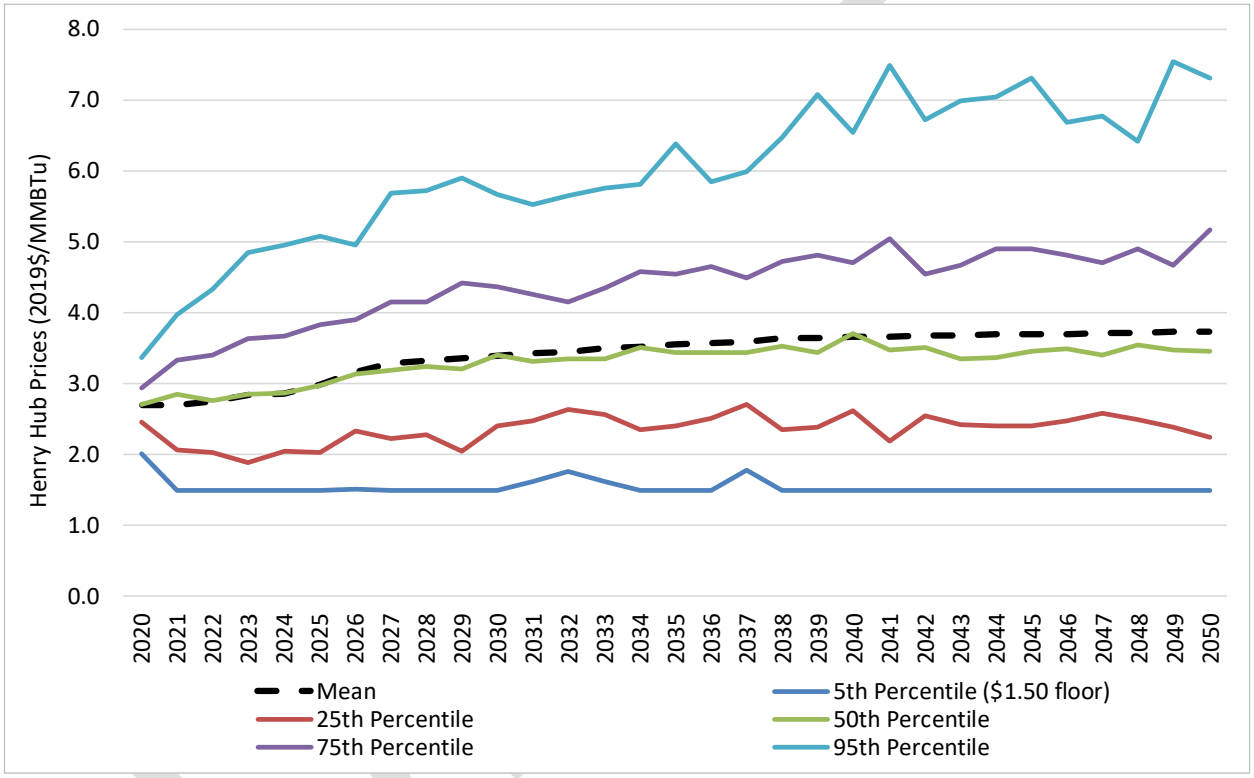
Siemens PTI developed natural gas price stochastic distributions for the benchmark natural gas commodity price at the Henry Hub market point. These stochastic distributions are first based on the expected value forecast of PIRA Energy Group's[23] view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2020-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2050, volatility calculated from the past 10 years is used. This allows gas price volatility and uncertainty to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility.

[22] Reductions in load in 2021 and 2026 are a result of the expiration of wholesale sale commitments.
[23] PIRA Energy Group was acquired by S&P Global Platts in 2016. It is a nationally recognized energy forecasting organization.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

The 95th percentile probability bands are driven by increased gas demand (e.g., coal unit retirements) and potential fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions. Exhibit 41 shows the stochastic distributions for the fuel inputs. The natural gas price stochastic inputs represent the possible outcomes for Henry Hub commodity prices. Siemens PTI then layers the natural gas price basis on top of the Henry Hub prices to provide the delivered gas price to the OUC and FRCC gas-fired power plants.

Exhibit 41: Natural Gas (Henry Hub) Price Distribution (2019$/MMBtu)



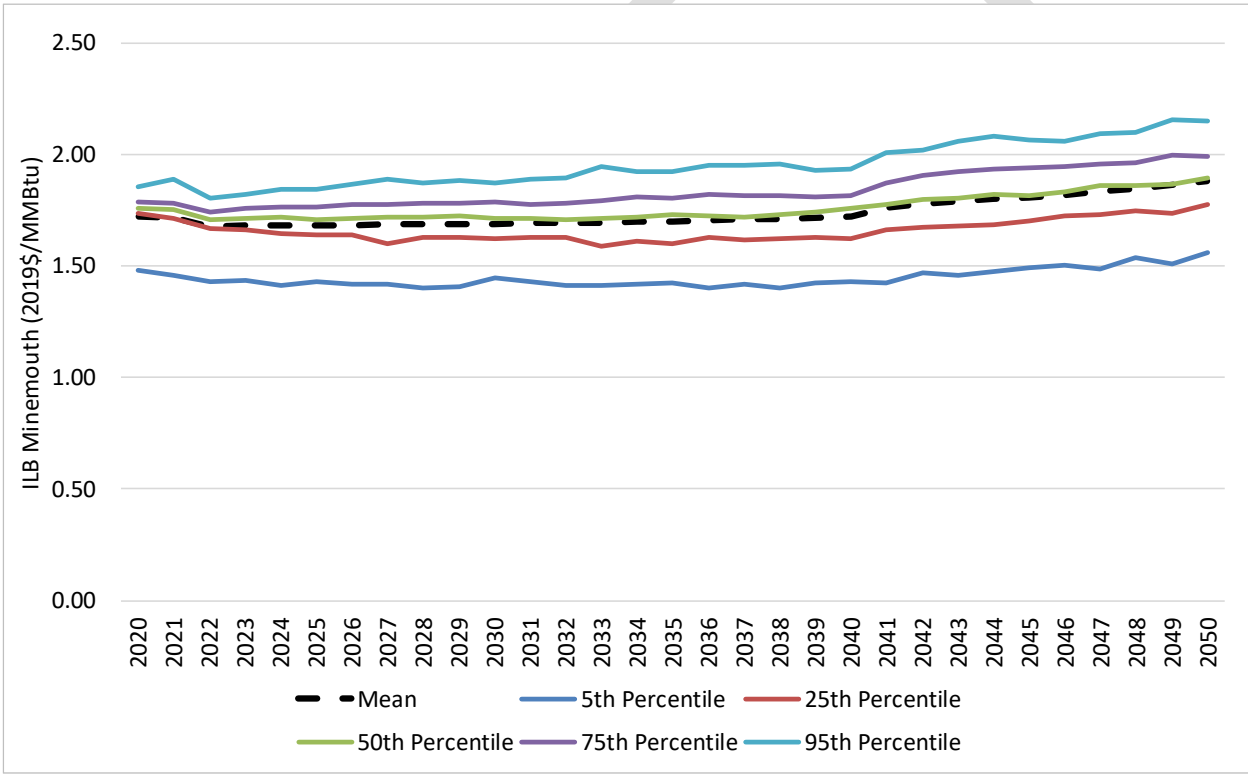
Source: Siemens PTI

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

7.3.3 Coal Price Distributions

Siemens PTI developed coal price stochastic distributions for the Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois (ILB) and Powder River (PRB) basins. These stochastic distributions are first based on an Energy Ventures Analysis[24] expected view of coal prices with probability bands then developed based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Market (NYMEX) Exchange. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX. The coal commodity price stochastic variations shown in Exhibit 42 are based on ILB Minemouth prices, applicable to OUC's coal plants. Siemens PTI adds individual transportation adders to represent the delivered coal prices to OUC and FRCC coal-fired power plants.

Exhibit 42: ILB Minemouth Coal Price Distribution (2019$/MMBtu)



Source: Siemens PTI

7.3.4 Emission Price Distributions

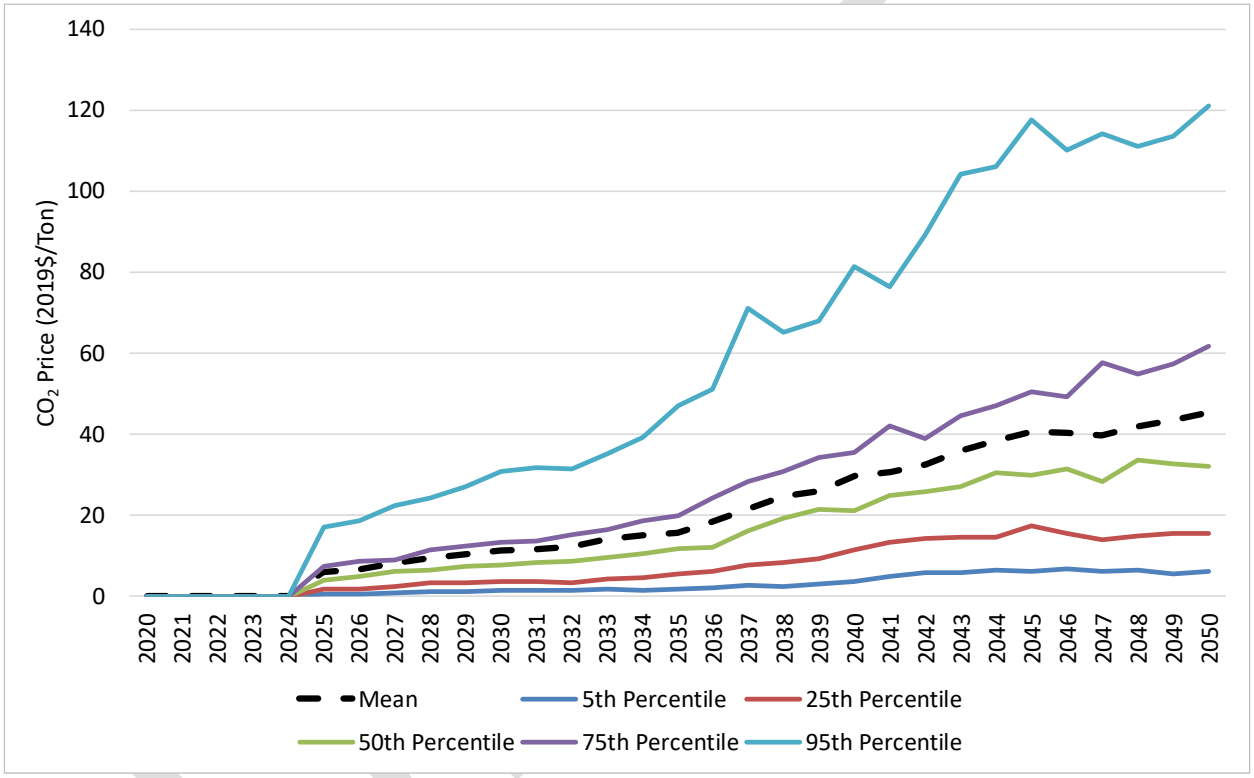
Siemens PTI developed uncertainty distributions around CO_2 compliance costs, which were used to capture the inherent risk associated with regulatory compliance requirements. The technique to develop CO_2 costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets

[24] Energy Ventures Analysis is an independent nationally recognized energy forecasting organization.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

(only regional markets in California and the northeast) to estimate the parameters for developing CO_2 costs distributions. The expected value (mean of the distribution) reflects a view that some type of legislation will likely occur in the mid-2020s. Previous studies of a proposed trading mechanism as well as analysis on the requirements to meet the Paris Agreement showed prices rising to about $30/short ton by 2040. The bottom end of the distribution assumes little future regulation, while the top end reflects the inclusion of social cost of CO_2 emissions. The portfolios are designed without considering CO_2 prices and are only exposed to the costs associated with emissions through the stochastic analysis.

Exhibit 43: CO_2 Price Distribution (2019$/short ton)



Source: Siemens PTI

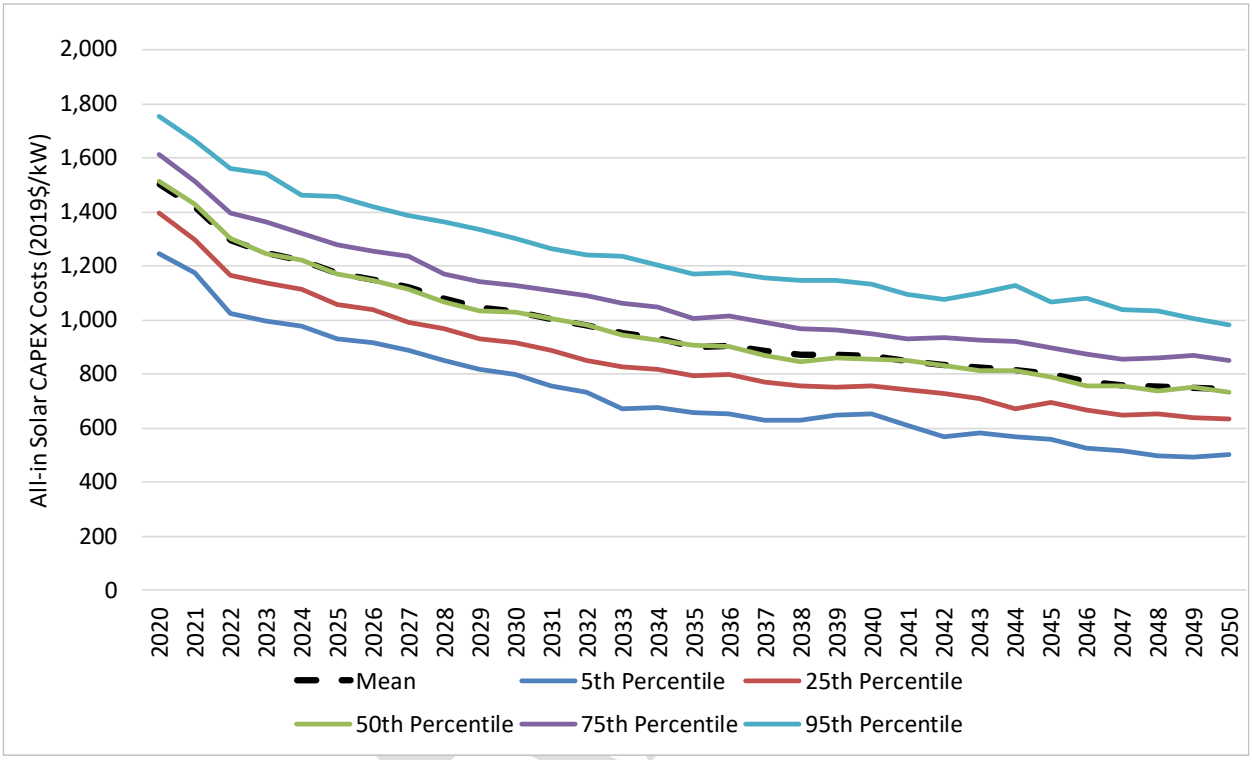
7.3.5 Capital Cost Distributions

Siemens PTI developed the uncertainty distributions for the cost of new entry units by technology type, which were used for determining the economic new builds in FRCC and SERC based on market signals. These technologies included gas peaking units, gas combined cycle units, solar, wind, and Li-on battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a deterministic Base Case view of future all-in capital costs, historical costs, and volatilities, and a sampling of results to develop probability bands around the Calibration Portfolio outlook; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events such as leaps in technological innovation. Additional detail on the stochastics

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

methodology is provided in Appendix B: Stochastics. Exhibit 44 to Exhibit 47 shows stochastic variations related to the all-in capital costs for various technologies. The stochastic variations in these costs are only implemented for capacity additions built by other utilities, thus have little impact on costs shown for the portfolios analyzed in this EIRP. Regional multipliers are applied to the costs for use in this analysis.

Exhibit 44: 74.5 MW Solar Capital Costs Distribution (2019$/kW)

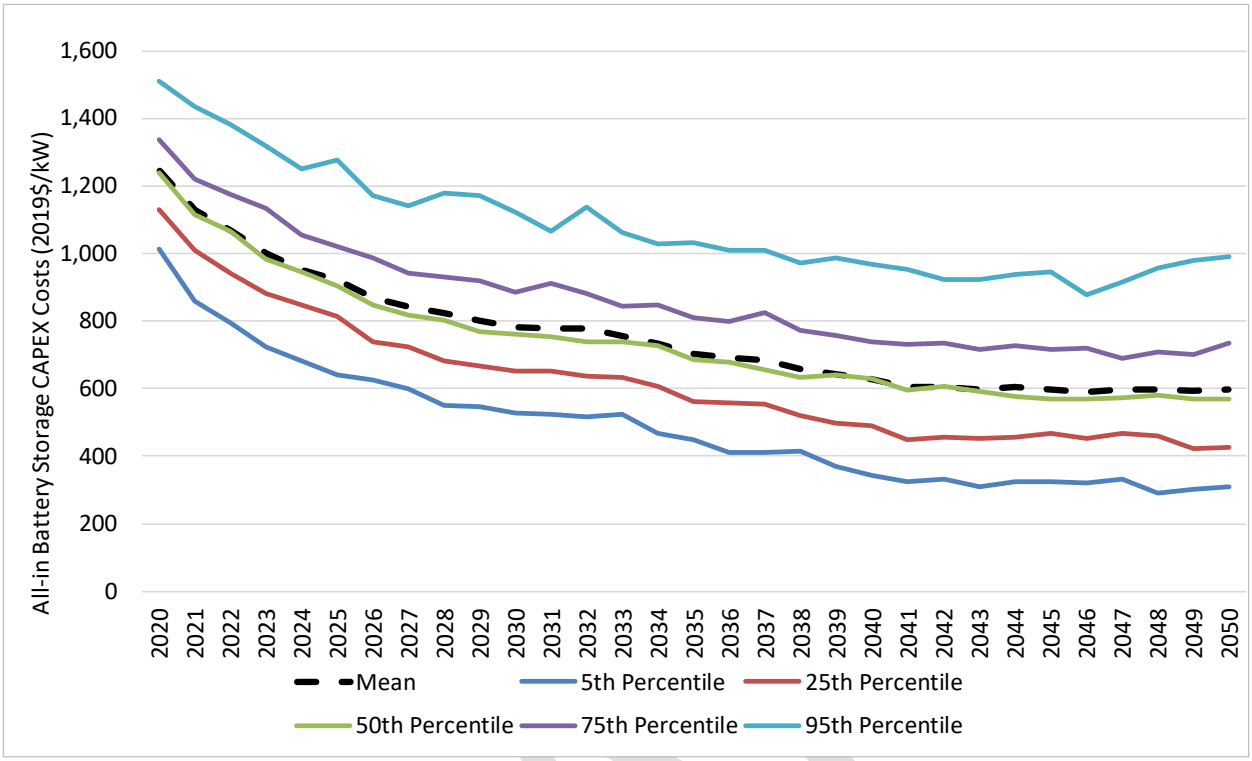


Source: Siemens PTI

DRAFT

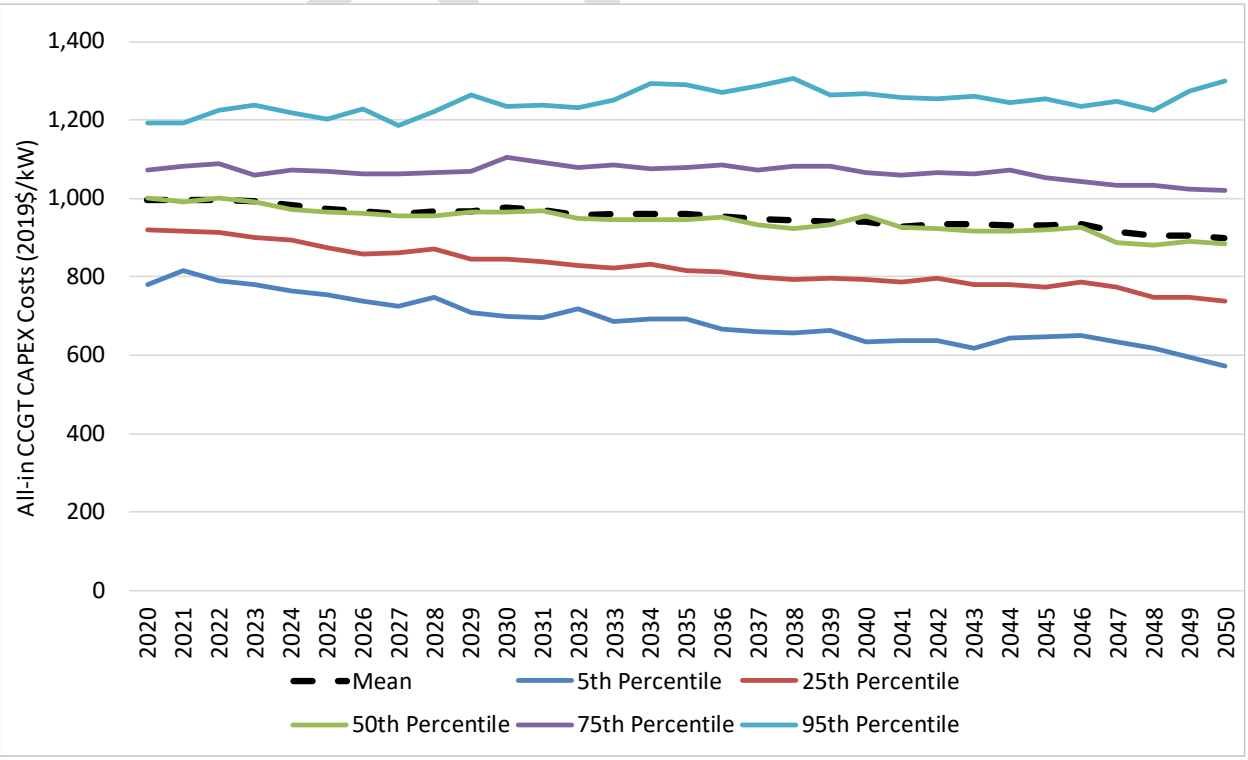
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 45: 50 MW Lithium-Ion 4-hour Battery Storage Capital Costs Distribution (2019$/kW)



Source: Siemens PTI

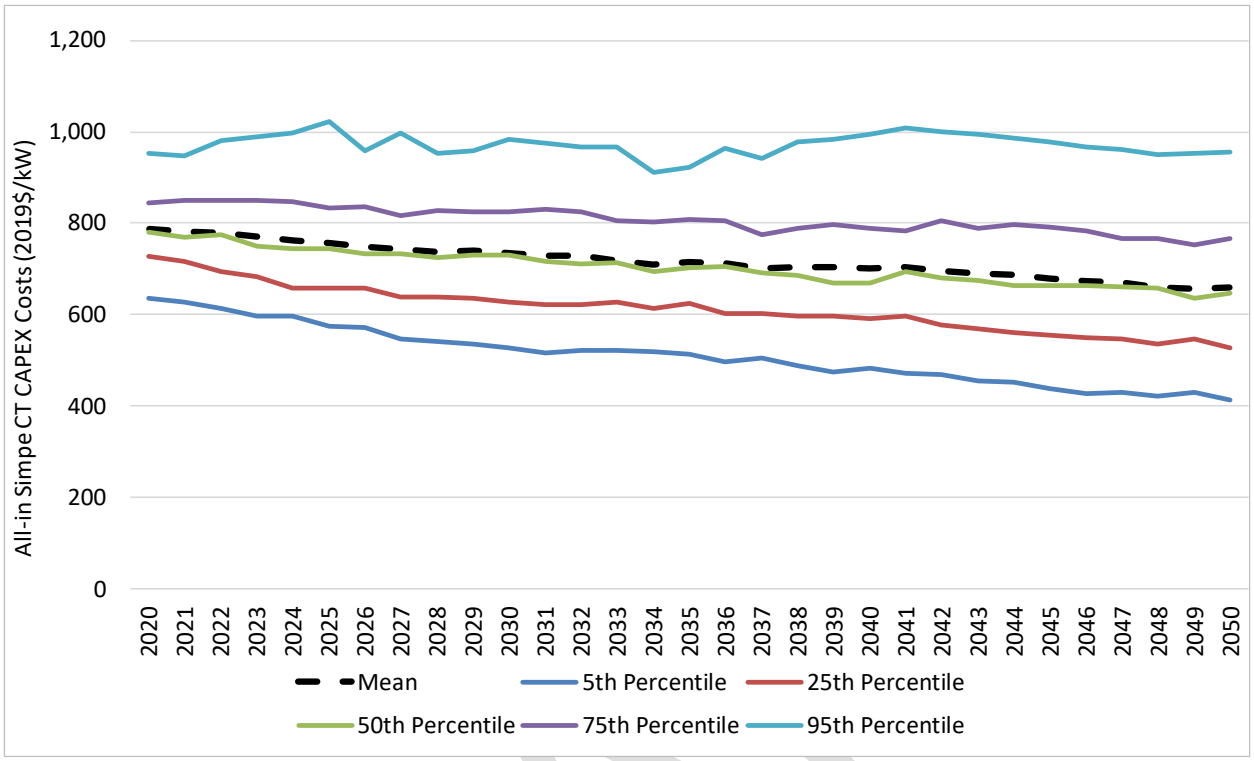
Exhibit 46: Advanced 2x1 Combined Cycle Capital Costs Distribution (2019$/kW)



Source: Siemens PTI

Unrestricted Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Exhibit 47: Advanced Simple Cycle Frame CT Capital Costs Distribution (2019$/kW)



Source: Siemens PTI

7.3.6 Cross-Commodity Correlations

Siemens PTI captured the cross-commodity correlations in the stochastic process. This is a unique stochastic process for natural gas, coal, and CO_2 prices. The feedback effects are based on statistical relationships between coal and natural gas switching and the variable cost of coal and natural gas generators. Siemens PTI conducted a fundamental analysis to define the relationship between natural gas and coal dispatch costs and demand. The dispatch costs of natural gas and coal were calculated from the natural gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, natural gas demand from the previous year was adjusted to reflect the corresponding change in demand. A natural gas price delta was then calculated based on the defined natural gas demand. This natural gas price delta was then added to the natural gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

8. Analysis Results and Comparisons

Siemens PTI conducted an extensive analysis of the options available to OUC for fulfilling its energy demand through 2050. The analysis included conventional and renewable energy generation, and battery storage systems both in OUC's service territory and more generally in the broader FRCC and SERC footprints, as well as a level of energy efficiency commensurate with OUC's current suite of demand side management measures. Additionally, the analysis accounts for electric vehicle load and incorporates a detailed study of distributed solar generation conducted independently of this EIRP by the National Renewable Energy Laboratory (NREL). Lastly, this analysis limited purchases and sales to historical numbers to provide an accurate representation of the bilateral energy marketplace in Florida.

The overall analysis considers a multitude of metrics across all the Attributes mentioned in Section 2.4. The results of the analysis based on all of these metrics can be observed in Exhibit 56. The colors represent the performance of each portfolio on each metric. A predominance of green is favorable, and a predominance of red is unfavorable. The analysis concluded that the Modular Nuclear, Gas Conversion 2026/2029, Gas Conversion 2036/2040 Portfolios perform the best out of all Candidate Portfolios. Each Attribute and associated metrics are explained in more detail in the next section.

8.1 Reliability

Through public and stakeholder engagement, it was determined that the Reliability metric is the most important and is weighted at 35% in the final balanced scorecard roll-up. From a Reliability perspective, all Candidate Portfolios were designed to meet or exceed the minimum reserve margin required by the Florida Public Service Commission. The combination of the Unforced Generation Capacity (UCAP) + Capacity Import Limit (CIL) must be more than 115% of the annual peak demand. Additionally, each portfolio is designed to be self-sufficient under expected conditions. In other words, each portfolio can supply all OUC's energy demand throughout the entire forecast horizon, without having to rely on imports from surrounding utilities under expected supply and demand conditions. Exhibit **48** shows how each portfolio performed on the Reliability metrics.

Next, as discussed previously, two metrics comprise the Reliability Attribute. The first metric is the first year occurrence of unserved energy determined through Siemens PTI's Cloud Cover analysis. The second metric is the technology diversity of each portfolio by the end of the forecast (2050). Each of these metrics are weighted equally for the ranking. The results across these metrics are discussed in further detail below.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 48: Reliability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Coversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
1st Year Cloud Cover U-E	First Year	Never	2036	2040	2050	2050	2027	2036	Never
2050 Technology Diversity	Tech Count	5	4	2	4	4	4	5	4

Source: Siemens PTI

Cloud Cover Analysis

The cloud cover analysis observes the first year in which there is unserved energy due to a 70% reduction in solar output from cloud cover during the highest demand week, occurring in August. As Exhibit **48** shows, the Calibration Portfolio and Modular Nuclear Portfolio never incur unserved energy under this condition. For the Calibration Portfolio this is due to heavy reliance on fossil-fuel powered plants, which are unaffected by the cloud cover. The Modular Nuclear Portfolio includes a 570MW nuclear powered unit, a generation source not impacted by cloud cover. It also contains sufficient energy storage to provide flexibility for the energy in the OUC system. Both the Gas Conversion 2026/2029 Portfolio and Gas Conversion 2036/2040 Portfolio perform well in the cloud cover analysis. The first year of unserved energy occurs in 2050, which is when these portfolios retire the Stanton A and B units to meet the 2050 Net Zero CO_2 target.

2050 Technology Diversity

This metric observes the number of different types of technology within the portfolio in 2050. The technology types include coal-fired plants, natural gas-fired plants, solar, wind, nuclear, and storage. The Calibration Portfolio and Wind-by-Wire Portfolio achieve the highest technology diversity. The Calibration Portfolio has the following technologies in 2050: natural gas-fired plant, nuclear, coal-fired plant, solar, and storage. The Wind-by-Wire Portfolio has the following technologies in 2050: natural gas-fired plant, nuclear, solar, storage, and wind.

8.2 Affordability

The second most important Attribute is Affordability and is weighted at 24% in the final balanced scorecard. The Affordability of the portfolios is important because it ultimately determines the costs for OUC to serve all load. There are many cost components that feed into the metrics shown in Exhibit 49, including fuel costs, fixed operating and maintenance costs, variable operating and maintenance costs, emission costs, and sales and purchases. Since costs occurring early in the forecast have higher value in terms of time value, the metrics weigh 2020-2030 costs at 50%, 2020-2050 costs at 10%, 2020-2030 uncertainty at 30%, and 2020-2050 uncertainty at 10%. Costs and uncertainty as shown in Exhibit 49 are measured in millions of dollars and standard deviation in millions of dollars, respectively.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 49: Affordability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Cost 2020-2030	PV 2020 $M	$3,108	$3,137	$3,354	$3,497	$3,127	$3,762	$3,167	$3,142
Cost 2020-2050	PV 2020 $M	$7,319	$9,257	$10,078	$8,596	$8,585	$11,180	$8,877	$9,098
Uncertainty 2020-2030	Std Dev Cost	$342	$435	$392	$333	$459	$302	$416	$353
Uncertainty 2020-2050	Std Dev Cost	$1,119	$942	$929	$625	$1,042	$549	$835	$705

Source: Siemens PTI

Present Value of Cost 2020-2030

This metric calculates the present value of costs over the 2020-2030 time horizon. As Exhibit 49 shows, the portfolio that performs best on this metric is the Calibration Portfolio since it does not aim to meet any of the Net Zero CO_2 targets. Out of the Candidate Portfolios, the Gas Conversion 2036/2040 Portfolio performs the best, with Net Zero CO_2 by 2050 and the Modular Nuclear Portfolio coming in close second and third, respectively. The Coal Retirement 2022/2026 Portfolio performs worst in this metric because the retired coal units need to be replaced with solar and battery storage early in the forecast. The capital investments associated with adding this capacity drives up the portfolio costs significantly.

Present Value of Costs 2020-2050

This metric calculates the present value of costs over the full forecast horizon. Exhibit 49 shows that the Calibration Portfolio performs best in this metric for the same reasons described above. The Candidate Portfolios that perform best in this metric are the Gas Conversion portfolios. They can take advantage of the existing infrastructure at the Stanton Energy Center and convert coal to a natural gas-fired plant at a fraction of the costs of an entirely new combined cycle gas turbine plant. Additionally, converting the coal units significantly reduces the investment costs in solar and storage capacity. Again, the Coal Retirement 2022/2026 Portfolio performs worst in this metric due to the early coal retirement.

Present Value of Uncertainty 2020-2030

This metric calculates the present value of standard deviation of portfolio costs. The portfolio that performs best in this metric is the Coal Retirement 2022/2025 Portfolio because it retires a significant portion of its fossil-fuel fired capacity early in the forecast. Therefore, it is less exposed to uncertainty around fuel prices as well as emission prices. The Gas Conversion 2026/2029 Portfolio also performs well in this metric because it is less exposed to volatility around the emission prices by converting the heavy emitting coal units to gas units.

Present Value of Uncertainty 2020-2050

Similar to the Uncertainty 2020-2030 metric, this metric calculates the present value of standard deviation of the portfolio costs, but over the full forecast horizon. Again, the Coal Retirement 2022/2026 Portfolio performs best in this metric and the Gas

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Conversion 2026/2029 Portfolio comes in second for the same reasons described before. However, the Calibration Portfolio performs worst in this category because it becomes highly exposed to the increasing volatility of gas and CO_2 prices, which means more upside risk late in the study horizon (shown in Exhibit 49).

8.3 Sustainability

Sustainability is the third most important Attribute and is weighted at 22% in the final balanced scorecard, similar to Affordability. The metrics for this Attribute measure the probabilities of meeting the 2030, 2040, and 2050 Net Zero CO_2 targets, as well as the percentage of clean energy generated in the portfolio in 2050. All of these metrics are weighted equally at 25%. Exhibit 50 shows how each portfolio performs across different metrics for this Attribute.

Exhibit 50: Sustainability Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Probability of Reduction Target 2030	Probability	5%	5%	25%	95%	5%	95%	5%	5%
Probability of Reduction Target 2040	Probability	5%	95%	75%	95%	50%	95%	95%	95%
Probability of Reduction Target 2050	Probability	5%	95%	95%	95%	95%	95%	95%	95%
Clean Energy Gen in 2050	%	15%	92%	100%	98%	97%	93%	87%	93%

Source: Siemens PTI

Probability of Reduction Targets

The probability of meeting reduction targets can be broken into three different metrics: Probability of meeting 2030 reduction target, 2040 reduction target, and 2050 reduction target. As Exhibit 50 shows, the only two portfolios that have a 95% probability of meeting the 2030 reduction target under varying market conditions are the Gas Conversion 2026/2029 Portfolio and Coal Retirement 2022/2026 Portfolio. All other portfolios have lower chances of meeting the 2030 goal because they retire the Stanton 1 and 2 coal units after 2030. Therefore, converting or retiring the coal plants are crucial in meeting the 2030 goal under varying market conditions.

As for the probability of meeting the 2040 reduction target, more portfolios are able to achieve 95% probability because of the retirements of the Stanton 1 and 2 coal units. The only portfolios that do not have a 95% probability of meeting this target are the Calibration Portfolio and Gas Conversion 2036/2040 Portfolio.

Again, the Calibration Portfolio only has a below 5% probability of meeting the 2050 reduction target because it keeps all fossil units. All Candidate Portfolios have a 95% probability of meeting the 2050 emission reduction target because each portfolio has retired the Stanton 1 and 2 coal units before 2050.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Clean Energy Generation 2050

As Exhibit 50 shows, all of the Candidate Portfolios perform very well in this metric. As long as a portfolio achieves above 90% clean energy generation, it is ranked the best. Any portfolio with less than 90% clean energy generation are ranked lower accordingly.

8.4 Resiliency

The last Attribute is Resiliency and it has a relative weight of 19%. This Attribute is ranked lowest, nevertheless, it is very important for the portfolios to withstand the unusual events that disrupt the electricity system within the Florida service area. The metrics based on the scenarios are weighted equally. Each metric measures the total amount of unserved energy over the two-week period with the highest demand (occurring in August) and sums the unserved energy occurring in 2025, 2035, and 2045 to provide the total amount of unserved energy in the portfolio. Exhibit 51 shows how each portfolio performs across the assumed scenarios and U-E stands for unserved energy.

Exhibit 51: Resiliency Attribute Metrics and Results

Metrics	Units	Calibration Portfolio	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Conversion 2026/2029	Gas Conversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
East FL Hurricane U-E 2025, 2035, 2045	MWh	510,259	449,274	416,852	416,456	454,814	517,701	473,178	513,767
West FL Hurricane U-E 2025, 2035, 2045	MWh	76,294	128,278	269,945	126,960	105,418	196,911	155,009	65,021
Gas Disruption U-E 2025, 2035, 2045	MWh	288,065	79,910	96,197	225,334	137,031	150,882	131,381	114,699

Source: Siemens PTI

East Coast Hurricane

This scenario calculates the unserved energy associated with a major hurricane on the east coast of Florida. As Exhibit 51 shows, this disruption scenario results in the highest amount of unserved energy due to the location of Orlando within the Florida peninsula. The portfolio that performs worst in this scenario is the Coal Retirement 2022/2026 Portfolio. Exhibit 52 shows the Coal Retirement 2022/2026 Portfolio incurs consistently high unserved energy in each year of the analysis. The reason is that the Coal Retirement 2022/2026 Portfolio heavily relies on solar and storage early in the forecast and solar output is reduced by 75% in the first week and 50% in the second week (Section 2.4.4) in the scenario. The second worst performing portfolio is Modular Nuclear Portfolio because it heavily relies on the nuclear unit in 2045 and its output is reduced by 100% in the first week and 50% in the second week of the disruption scenario.

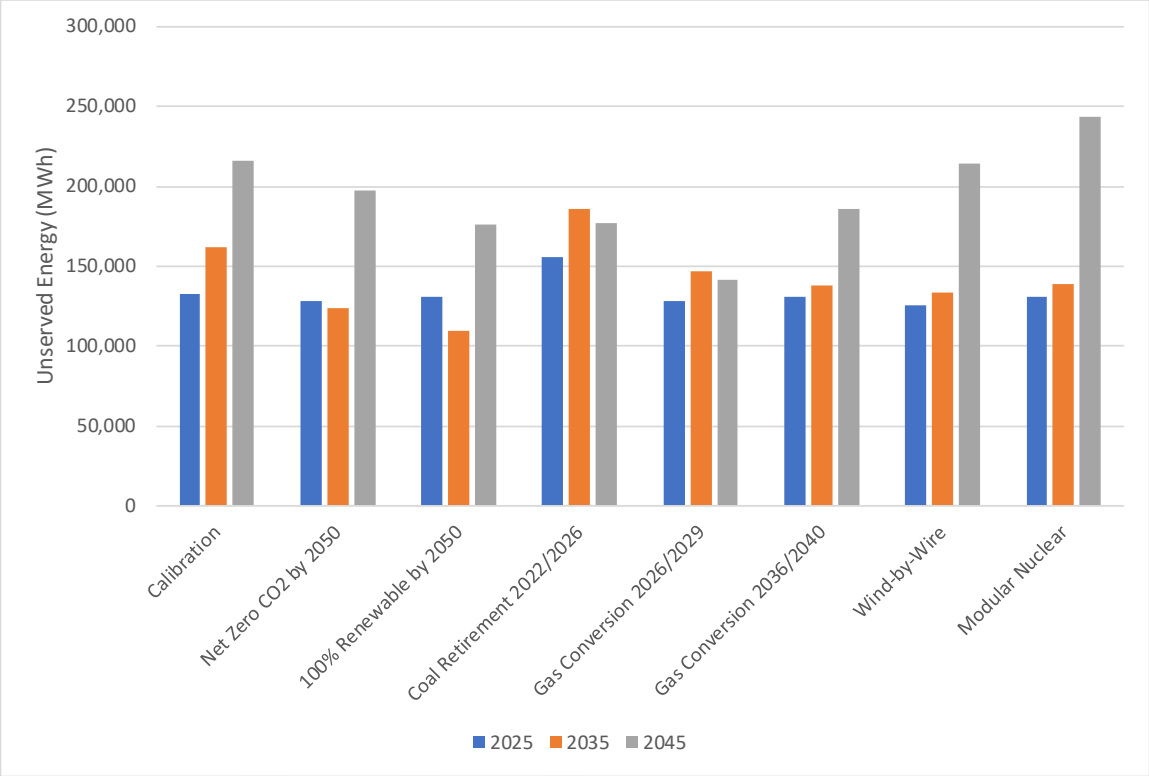
The portfolios that perform best in this scenario are the 100% Renewable by 2050 and the Gas Conversion 2026/2029 Portfolio. The 100% Renewable by 2050 Portfolio performs better because it retires both Stanton 1 and 2 coal plant by 2040, which is later than all other portfolios, and because it has more solar and storage capacity to meet the 100% renewable target. The Gas Conversion 2026/2029 performs better

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

compared to the Gas Conversion 2036/2040 Portfolio since in 2045 it has more solar capacity.

Exhibit 52: East Coast Hurricane Detailed Results



Source: Siemens PTI

West Coast Hurricane

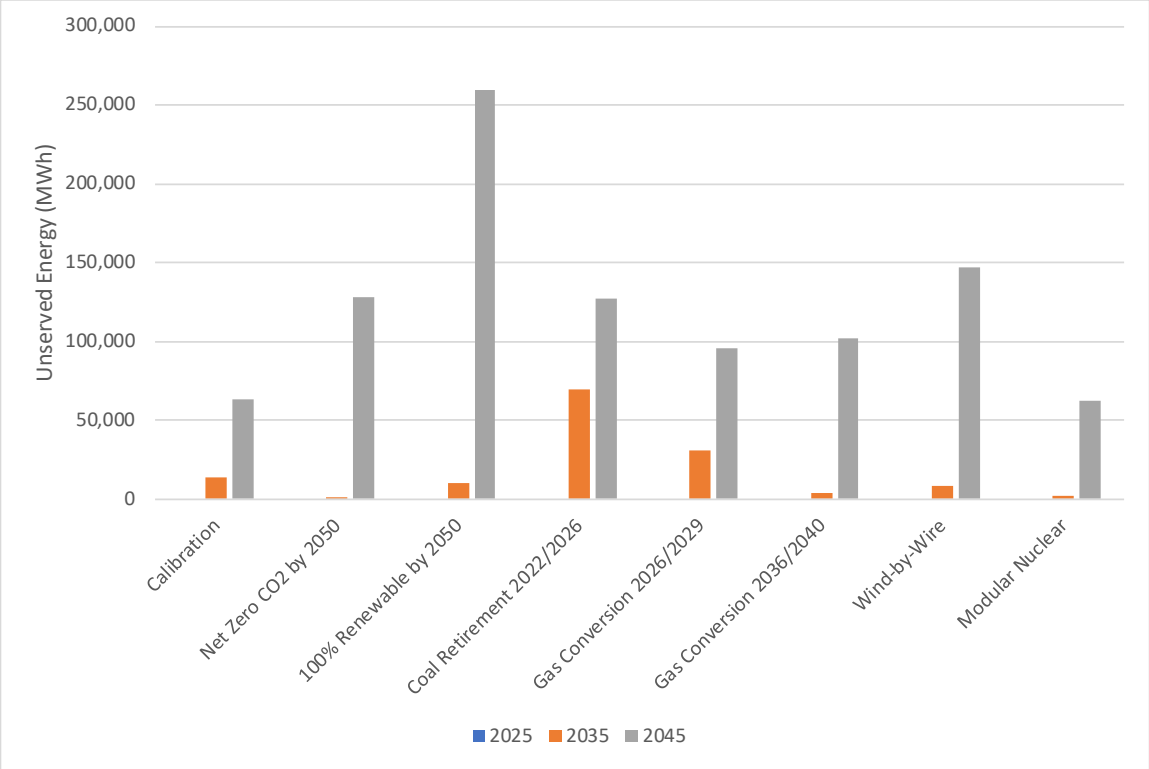
This scenario quantifies unserved energy as a result from a major hurricane occurring in the Gulf of Mexico. Because of Orlando's location within the Florida peninsula, this scenario has less of an impact on the Orlando service area. As shown in Section 2.4.4, the only resource affected by a west coast hurricane is assumed to be solar. As Exhibit 51 shows, the portfolios that perform best in this scenario are the Calibration Portfolio and Modular Nuclear Portfolios. Since the Calibration Portfolio and Modular Nuclear Portfolio have less solar capacity in 2035, less unserved energy is observed in this year. In 2045, the Calibration Portfolio maintains a lot of dispatchable generation through the added natural gas-fired combined cycle and peaker capacity. The Modular Nuclear Portfolio has 570MW of nuclear capacity in this year and the portfolio can rely on the steady output of this plant.

The two portfolios that perform worst in this hurricane scenario are the 100% Renewable by 2050 Portfolio and Coal Retirement 2022/2026 Portfolio. This is due to the heavy reliance on solar energy in these portfolios, which is the only technology affected by this hurricane scenario. 2045 shows the most impact for the 100% Renewable by 2050 Portfolio because the Stanton A unit is retired, which means that

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

this portfolio has much less dispatchable capacity that can make up for the loss of solar output.

Exhibit 53: West Coast Hurricane Detailed Results



Source: Siemens PTI

Gas Pipeline Disruption

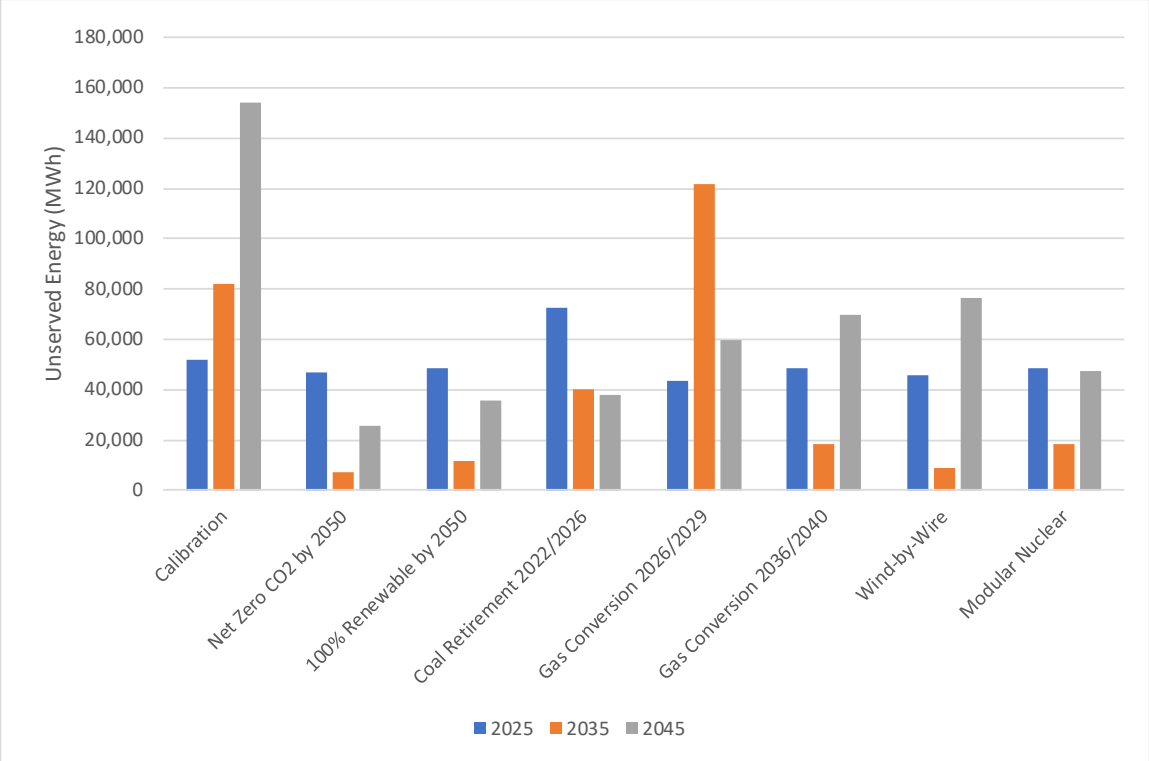
The last scenario analyzed for the Resiliency Attribute is a large gas pipeline disruption in the Florida peninsula. As the name suggest, this scenario only affects natural gas-fired plant output (100% in the first week, 50% in the second week) by significantly reducing the amount of natural gas that can be delivered to various gas plants throughout the FRCC and OUC service areas. As Exhibit 54 shows, most portfolios perform comparably in 2025. However, the Coal Retirement 2022/2026 Portfolio has slightly more unserved energy in 2025 because of a Stanton coal unit retiring in 2022. Overall, the portfolios that perform worst in this scenario are the Calibration and Gas Conversion 2026/2029 Portfolio since these portfolios rely heavily on gas capacity through most of the forecast. The Gas Conversion 2026/2029 Portfolio has the most unserved energy in 2035 due to the reasons described above. The Calibration Portfolio has the most unserved energy in 2045 because of large amount of gas capacity installed in this year.

The portfolios that perform best in this metric are the Net Zero CO_2 by 2050 Portfolio and 100% Renewable by 2050 Portfolio. In 2025 these portfolios perform similar to the other Candidate Portfolios. However, these portfolios excel in 2035 and 2045. In 2035,

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

these portfolios maintain both Stanton coal units, providing sufficient reliable and dispatchable capacity, similar to some other Candidate Portfolios. In 2045, after the retirement of the Stanton coal units, these portfolios have a significant amount of solar and battery storage capacity to assist with the loss in gas capacity in this year.

Exhibit 54: Gas Pipeline Disruption Detailed Results



Source: Siemens PTI

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

8.5 Findings and Recommendations

This EIRP report is designed to provide OUC with the information needed to consider the tradeoffs associated with the different Candidate Portfolios. By comparing all Candidate Portfolios, this study was able to establish some key findings.

Exhibit 55: EIRP Key Findings

1. Although attainable, developing a high renewable portfolio that meets all of OUC's load under expected conditions without relying on purchases can significantly increase costs.
2. Retiring or converting the Stanton coal units early in the forecast is essential to achieving a high probability of meeting the Net Zero CO_2 target and interim targets under varying conditions.
3. Converting the Stanton coal units instead of retiring them greatly reduces the need for solar and storage capacity, while still significantly reducing emissions.
4. Converting the Stanton coal units enables OUC to bridge technology advances and take advantage of technology improvements as well as reductions in costs of these technologies. Additionally, potential stranded costs are avoided, and the converted units can use existing transmission infrastructure at the Stanton Energy Center.
5. Maintaining a highly diverse portfolio assists with better performance on the key Attributes of Reliability, Affordability, and Resiliency.

Source: Siemens PTI

After rolling up the scores across the different metrics and weighting the Attribute as previously described, the resulting final balanced scorecard is presented in Exhibit 56. As described in Section 8.3, the only Candidate Portfolios that have a 95% probability of meeting all Net Zero CO_2 targets are the Gas Conversion 2026/2029 Portfolio and Coal Retirement 2022/2026 Portfolio. Out of these two portfolios, the Gas Conversion 2026/2029 Portfolio is the best performing portfolio with a weighted score of 3.0.

Exhibit 56: Final Balanced Scorecard

Attributes	Weight	Net Zero CO_2 by 2050	100% Renewable by 2050	Gas Converstion 2026/2029	Gas Coversion 2036/2040	Coal Retirement 2022/2026	Wind-by-Wire	Modular Nuclear
Reliability	35	3.5	3.0	2.0	2.0	4.0	3.0	1.5
Affordability	24	5.2	6.2	5.1	4.7	5.8	5.5	4.4
Sustainability	22	1.5	1.5	1.0	2.0	1.0	1.8	1.5
Resiliency	19	3.0	4.3	4.3	4.0	8.0	5.0	4.0
Total	**100**	**3.4**	**3.7**	**3.0**	**3.0**	**4.5**	**3.7**	**2.7**

Source: Siemens PTI

After considering the key findings and the balanced scorecard, this EIRP established the recommended refinements to the Leading Portfolio as described in the following section to determine the Optimized Portfolio.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

9. OUC's Optimized Portfolio

9.1 Introduction

After conducting the development and analysis of the original Candidate Portfolios, OUC and Siemens PTI identified the Gas Conversion 2026/2029 Portfolio as the Leading Portfolio as it was the best performing portfolio that maintained a 95% probability of meeting all Net Zero CO_2 targets throughout the forecast. Therefore, the Gas Conversion 2026/2029 Portfolio was used as a starting point and further refined to develop the recommended Optimized Portfolio.

9.2 Optimized Portfolio Advantages

The Optimized Portfolio provides the following advantages over the Leading Portfolio:

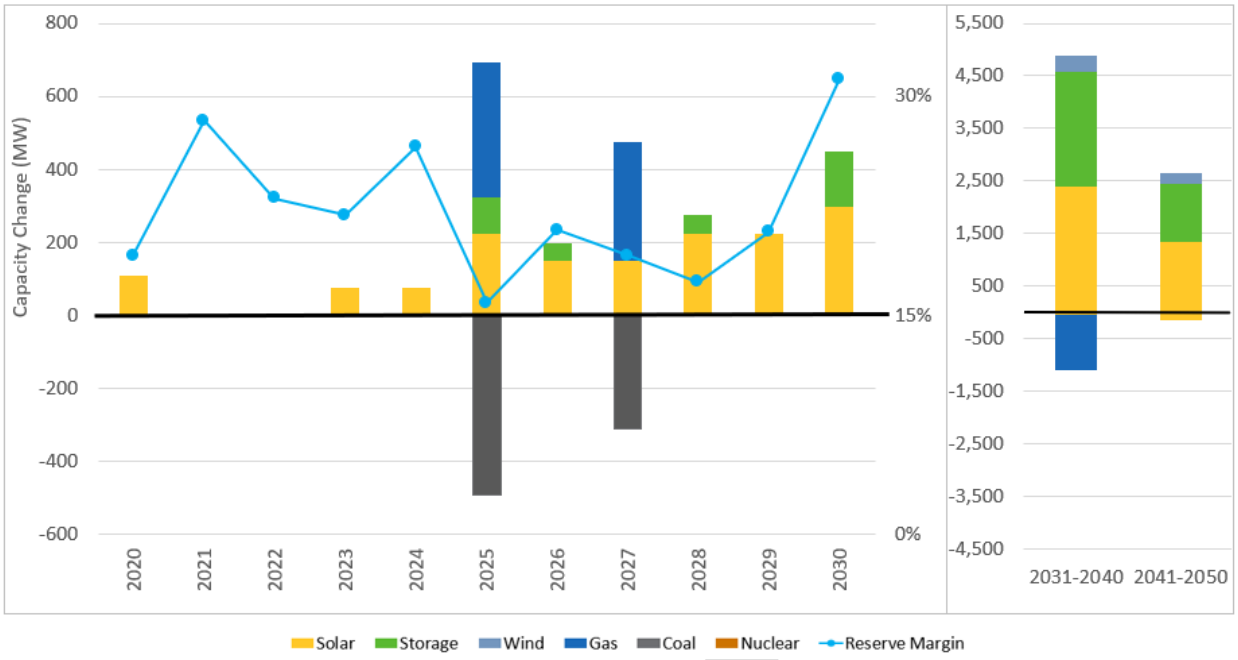
1. The Optimized Portfolio converts the Stanton coal units earlier – starting no later than 2025 and completed no later than 2027 compared to 2026 and 2029 for the Leading Portfolio. The converted gas units are planned to be retired by 2040.
2. The Optimized Portfolio reduces emissions by approximately 7.6 million tons over the forecast period compared to the Leading Portfolio under expected conditions.
3. Adding wind capacity late in the forecast period increases resource diversity, likely improving both Reliability and Resiliency compared to the Leading Portfolio.
4. The Optimized Portfolio incorporates a higher level of storage in the near-term, facilitating a potential higher level of Reliability.
5. The Optimized Portfolio avoids some operations costs, improving Affordability. It bridges technology advances while keeping the overall portfolio cost down.

These revisions made to the Leading Portfolio results in the portfolio illustrated in Exhibit 57 with the resource mix by technology shown in Exhibit 58.

DRAFT

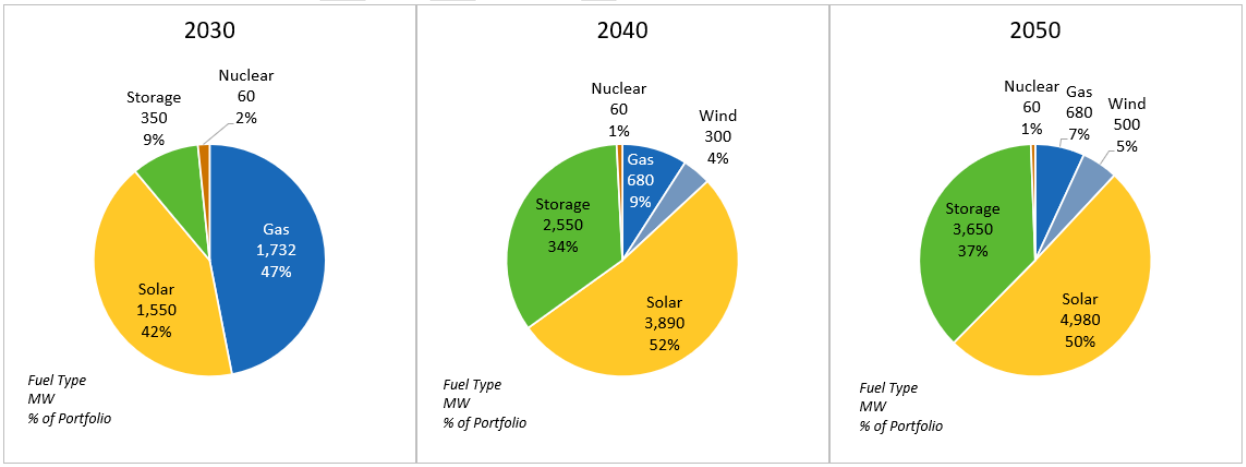
Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 57: Optimized Portfolio Build-Out (2020-2050)



Source: Siemens PTI

Exhibit 58: Optimized Portfolio Installed Capacity



Source: Siemens PTI

A brief description of the enhancements to the Optimized Portfolio within the context of the Attributes follows.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

9.2.1 Reliability

The Optimized Portfolio contains more technology diversity than the Leading Portfolio. This includes the natural gas conversions, solar, storage, wind, and nuclear. The increase in technologies in this portfolio is expected to contribute to its Reliability.

9.2.2. Affordability

The Optimized Portfolio bridges technology advances while keeping the overall portfolio cost down. Potential stranded costs are avoided by not spending resources for the construction of *new* natural gas-fired capacity and taking advantage of existing transmission infrastructure at the Stanton Energy Center. Gas conversion capital costs are 5 to 10% of the cost of a new Combined Cycle gas plant. This allows for the retirement of the converted natural gas-fired units by 2040 without the risk of stranded costs.

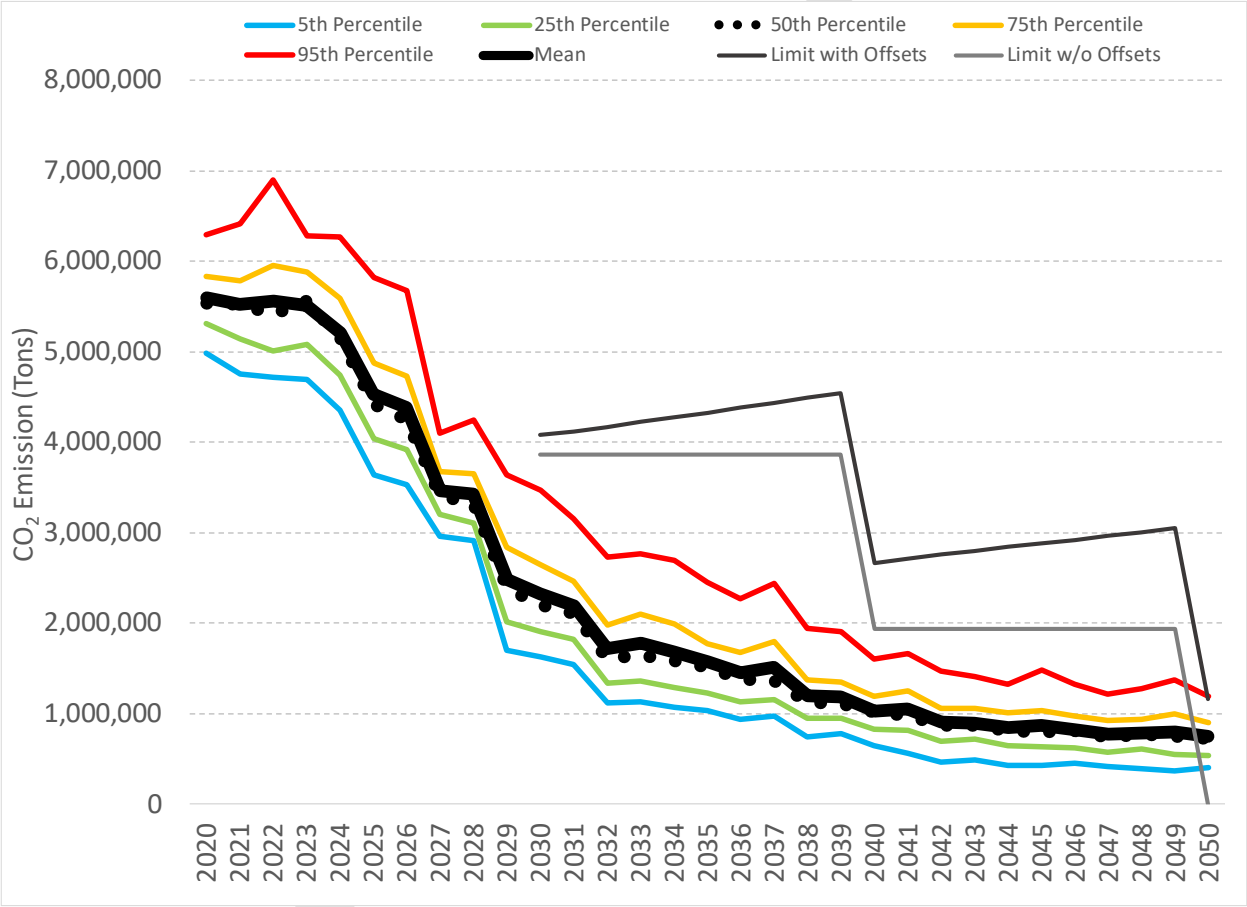
DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

9.2.2 Sustainability

The Optimized Portfolio introduces some changes to the Leading Portfolio to increase Sustainability. By converting the Stanton coal units earlier, it avoids the high CO_2 emissions from burning coal. Additionally, retiring the gas conversion units further reduces CO_2 emissions. The Optimized Portfolio reduces CO_2 emissions by approximately 7.6 million tons over the entire forecast compared to the Leading Portfolio. To put this into perspective, this is the equivalent of the annual emissions of approximately 1.7 million passenger cars.[25]

Exhibit 59: Optimized Portfolio CO_2 Emissions Stochastic Distributions



Source: Siemens PTI

Exhibit 59 illustrates the impact of retiring fossil fuel capacity on CO_2 emissions within the portfolio. CO_2 emissions are reduced when the coal units are converted to natural gas starting no later than 2025 and completed no later than 2027, after the Stanton A PPA ends in 2032, and upon the retirement of the conversion units.

As Exhibit 59 shows, the Optimized Portfolio maintains a 95% probability of meeting all Net Zero CO_2 target throughout the forecast period. The 2030 and 2040 interim targets are

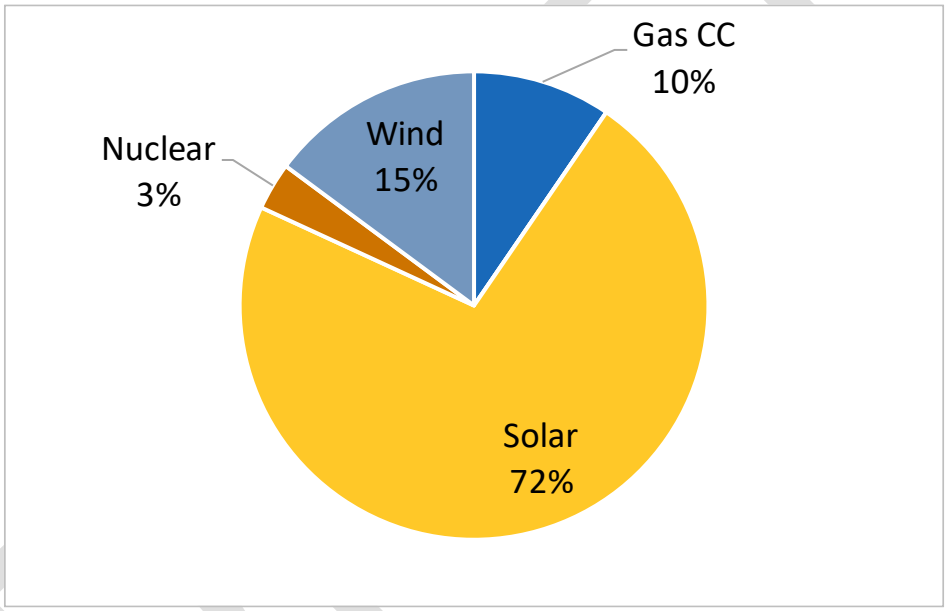
[25] This is based on data from EPA that calculates an annual average CO_2 emission of 4.6 metric tons for one passenger vehicle.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

expected to be met without the need for offsets through EV adaptation. In 2050, the offsets are required because the Optimized Portfolio maintains the Indian River gas peaker units and the Stanton A and B combined cycles to maintain dispatchable capacity to ensure Reliability.

The second metric within the Sustainability Attribute is the amount of clean generation in the portfolio in 2050 on an expected basis. Exhibit 60 shows the energy generation by technology in 2050 for the Optimized Portfolio. Solar generation makes up almost three-quarters of the generation in 2050. The other clean generation technologies (Nuclear and Wind) contribute another 18% of the clean generation. This provides a total of 90% non-emitting energy generation in 2050 for the Optimized Portfolio. The only fossil fuel fired capacity generating energy in 2050 is OUC's portion of the Stanton A and B combined cycle units. The Indian River peaker units are still operating but are generating a negligible amount of energy in 2050.

Exhibit 60: Percentage of Total Energy Generation (MWh) by Technology (2050)



Source: Siemens PTI

9.2.3 Resiliency

The addition of wind generation reduces the solar and storage required to achieve energy sufficiency. Energy from wind resources is generally available at different times of day from solar resources important for Reliability and Resiliency.

Once the gas conversion units are retired and replaced with wind capacity, the portfolio is more resilient. The Optimized Portfolio has a high technology diversity, including the gas conversion and wind capacity in the latter part of the forecast, minimizing the impact of the hurricane.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

10. Challenges and Opportunities

This EIRP present a way forward for OUC to meet its load while significantly reducing its CO_2 emissions. However, since the state of the market will change over the next few years, it is important to consider both the challenges and opportunities that the Optimized Portfolio may present across the different Attributes described in this analysis. The following challenges and opportunities can be considered in future EIRP analyses conducted for OUC.

10.1 Reliability

Reserve margin focused on capacity will become less relevant and *energy* sufficiency more relevant as intermittent resources become more prevalent in the resource mix. Solar intermittency challenges are more acute in Florida than other areas of the country that allow large areas to pool resources to take advantage of load and resource diversity.

10.2 Affordability

To ensure energy sufficiency from solar and storage during high demand periods, OUC will have an energy surplus during lower demand periods. Managing this energy surplus may provide benefits that help to contain costs while maintaining reliability and other important Attributes.

Increased solar capacity increases remote generation as compared to local generation, with implications for transmission wheeling cost, interconnection cost and potentially local jobs.

10.3 Sustainability

Unlike other parts of the country, solar energy is the only renewable resource currently economically viable at scale in Florida. Wind energy could be made available by mid-2030s and OUC will continue to monitor its availability. OUC will continue to evaluate and monitor emerging clean resources such as hydrogen, offshore wind and small modular nuclear technologies.

10.4 Resiliency

OUC will have greater reliance on transmission infrastructure. Greater geographical diversity of renewable energy will be required to minimize the risk of extreme weather. Generation diversity will need to remain part of the OUC strategy.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Appendix A: Technology Cost and Performance Assumptions

This summary includes national capital cost forecasts from Siemens PTI by technology class.[26] All capital cost assumptions are considered to be "all-in" overnight capital costs which include EPC costs (Engineering, Procurement, and Construction), developer costs (i.e. land acquisition, permitting, legal, etc.), and financing interest during construction. However, these capital costs only include onsite costs up to the point of interconnection.[27]

Estimates of unit cost are provided in

DRAFT

[26] Regional capital cost forecasts for FRCC and SERC are developed by applying regional multipliers from the EIA AEO to the Siemens national capital cost forecasts.
[27] Siemens "all-in" capital costs do not include additional transmission/interconnection costs past the busbar as these costs are highly variable and dependent on project specific details.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

- Exhibit 61. According to the American Association of Cost Engineers (AACE), this is a Class 4 estimate appropriate for a study with an expected accuracy range on the low side: -15% to -30%, and on the high side: +20% to +50%. Given the modularity and experience building most generation technologies, Siemens PTI believes the cost estimates we provide are closer to Class 3 estimates and within a tighter range of accuracy than AACE defines.
- The estimates are for typical units of a class (i.e. Advanced class CT = G, H, J, or HA CT models depending upon the vendor), the unit models presented are typical for the class, and do not necessarily represent the specific models used as a basis for the estimate. Specific units may be chosen during a procurement process when vendors provide both unit performance and cost guarantees.
- Performance (e.g. heat rates) are based on International Organization for Standardization (ISO) conditions. ISO Conditions means the reference temperature, humidity and pressure conditions established by the International Standards Organization. ISO Conditions means 59 degrees Fahrenheit and 60% relative humidity. Only in extreme cases (i.e. high elevations or exceptional temperatures) does Siemens PTI adjust performance estimates to locational specificity, which does not apply in Florida, though adjustments are made for local cost conditions.
- Provided estimates are "inside-the-fence" estimates and account for all EPC and owners costs, including interest during construction, insurance and taxes. They do not include the cost of fuel, water, or waste pipelines, rail, or transmission upgrades since the exact location of the study plant is unknown. A cost of interconnection was not included but a cost for fuel transport was included.
- Technology cost and performance estimates are based on a combination of public and private sources which provide a range of potential inputs. No single budgetary estimate source will exactly represent the performance of a given unit when constructed. Vendors will assess site conditions during a procurement process and develop a specific offer which guarantees both performance and cost.
- Vendors operate in a highly competitive market and they continually improve unit performance and cost. As a result, a given turbine model (i.e. F-class) will perform better two to three years from now than today, while still being termed "F-class." Thus, the studies and tools used to develop the performance and cost estimates may not represent the exact characteristics of a new unit purchased today, though the difference will be small, and the characteristics will remain within the bounds provided. Even vendor websites often lag in presenting their latest performance.
- Even within a given equipment model, customers have choices which influence performance and cost, and those choices are not always apparent. They may select wet or dry cooling, add evaporative cooling, require on-site gas compression, or add a range of duct firing capability, for example. This is one key reason Siemens PTI does not use project announcements in establishing technology cost and performance estimates. Announcements typically lack a clearly delineated supply scope and condition definition.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Siemens PTI capital cost forecasts are assumed for the year of commercial operation. Development timelines are considered for building new generation or storage, and interest during construction is included in the all-in capital cost estimation. Siemens PTI applied a weighted average cost of capital (WACC) of 6.3%, as provided by OUC, for plants OUC would finance.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 61: Siemens PTI New Resource Technology Cost and Financial Assumptions

Technology	Fuel	Construction Time (Yrs)	Winter Capacity (MW)		Average Heat Rate (Btu/kWh), HHV	VOM (2019$/MWh)	FOM (2019$/kW-yr)	Range of Capital Cost (2019$/kW)	Book Life
Advanced 1x1 CCGT, Fired	Nat. Gas.	3	605		6,800	$1.50	$15.60	$945-838	30
Conventional 1x1 CCGT, Fired	Nat. Gas.	3	385		7,000	$2.00	$17.50	$1005-892	30
Simple Cycle Conventional Frame 7FA CT	Nat. Gas.	2	225		8,900	$4.50	$12.50	$777-683	30
Simple Cycle Large Aero CT	Nat. Gas.	2	100		9,000	$5.50	$15.60	$1074-944	30
Simple Cycle Small Aero CT	Nat. Gas.	2	50		9,000	$5.50	$15.60	$1163-1023	30
Landfill Gas	RNG	2	5		11,575	$12.50	$17.50	$2578-2267	40
Utility Solar PV - Tracking (Large)	Sun	1	74.5		N/A	$0.00	20.80	$1148-738	20
Utility Solar PV - Tracking (Small)	Sun	1	10		N/A	$0.00	$20.80	$1236-795	20
Wind-by-Wire	Wind	2	100		N/A	$49.48	0	N/A	N/A
Lithium Ion Batteries (4 hrs.)	Elec. Grid	1	50 MW	200 MWh	N/A	$1.00	$32.80	$1201-580	20
Lithium Ion Batteries (4 hrs.)	Elec. Grid	1	5MW	20MWh	N/A	$1.00	$32.80	$1357-647	20
Flow Batteries (6 hrs.)	Elec. Grid	1	50MW	300MWh	N/A	$3.00	$28.10	$2075-781	20
Flow Batteries (6 hrs.)	Elec. Grid	1	5MW	30MWh	N/A	$3.00	$28.10	$2370-883	20
Solar + 4 hr Storage	Sun/Elec. Grid	1	50MW+ 12.5MW	50MWh	N/A	$1.00	$26.00	$1273-671	20
Nuclear SMR	Uranium	7	570		N/A	$15.00	$167.80	$9215-4734	40

Source: Siemens PTI

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Appendix B: Stochastics

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (CO_2), and capital costs.

B.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Siemens PTI developed stochastics around the load growth expectations for the OUC control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation as well as energy efficiency and demand-side management implementation.

Siemens PTI's long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook.

Finally, Siemens PTI benchmarked the projections against FRCC-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to FRCC's forecasts is undertaken during the quantum step, which is described below.

B.1.1 Load Forecast Process

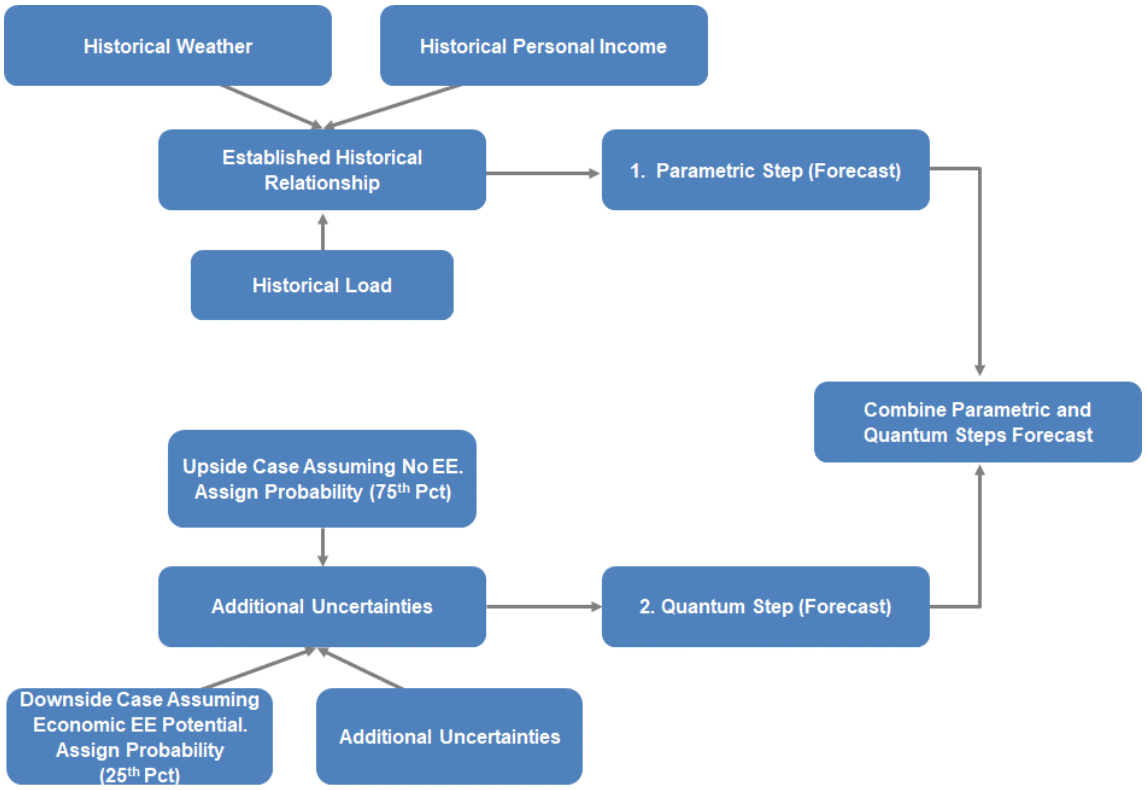
The process for developing stochastic distributions for OUC and surrounding FRCC and SERC zones loads begins with a deterministic estimation of load uncertainties, followed by parametric and quantum forecasts for the FRCC and SERC zones.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

Exhibit 62: Process for Developing Stochastic Distribution

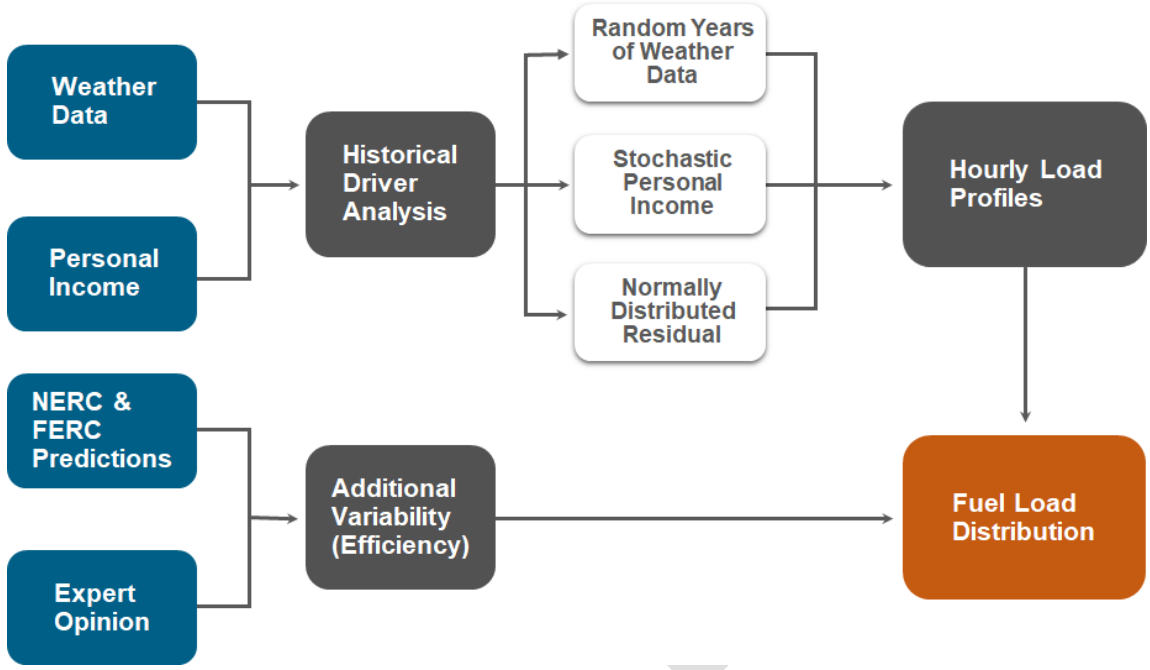


To address demand uncertainty in modeling and capture the risk associated with demand growth, Siemens PTI produced a distribution of monthly average and peak loads using the methodology described below and summarized in the following flow chart.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 63: Flow Chart to Address Load Uncertainty



Source: Siemens PTI

With respect to the historical driver analysis, we find that historical monthly weather data and personal income have explained changes in monthly average and peak load well. This relationship forms the basis for Siemens PTI's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of heating degree days, cooling degree days, humidity, and personal income.

$$Load_t = \alpha + \beta_1 * HDD_t + \beta_2 * CDD_t + \beta_3 * HUM_t + \beta_4 * PI_t + \xi_t$$

Where the independent variables are:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income
- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis
- t: Month of the year

A stepwise regression then calibrates this model for the historic net peak and average OUC load data. The stochastic distributions of the load were then computed by running 200 iterations on the independent variables as the randomly generated input parameters and applied to the equation and the calibrated model coefficients above.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

B.1.2 FRCC and SERC Forecast Load Uncertainty

The subsequent load stochastics propagation for the surrounding FRCC and SERC zones is conducted in a two-step process: a parametric step and a quantum step.

The parametric step separately employs the same econometric specification for the FRCC and SERC Balancing Authorities based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area). Siemens PTI uses the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region or balancing authority to assess the distribution of overall load growth conditions for each year of the forecast. The base average and peak demand forecasts are based on the average of the peak and average demand forecasts.

Siemens PTI benchmarks its outlook against the latest FRCC-sponsored load forecasting study, which shows the CAGR for the next 10 year study period. To produce load stochastics, Siemens PTI propagates three independent random paths: weather data, personal income, and a residual. Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Siemens PTI samples actual yearly paths from history. On average, we use about 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Siemens PTI adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

B.2 Gas Stochastics

Siemens PTI develops natural gas stochastic distributions for Henry Hub and other basis points. These stochastic distributions are based on a reference case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Siemens PTI has developed stochastics around the price at the Henry Hub (and other gas basis point as needed) based on historical volatility, current market forwards, and a long-term term fundamental view that considers the expected supply-demand balance. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

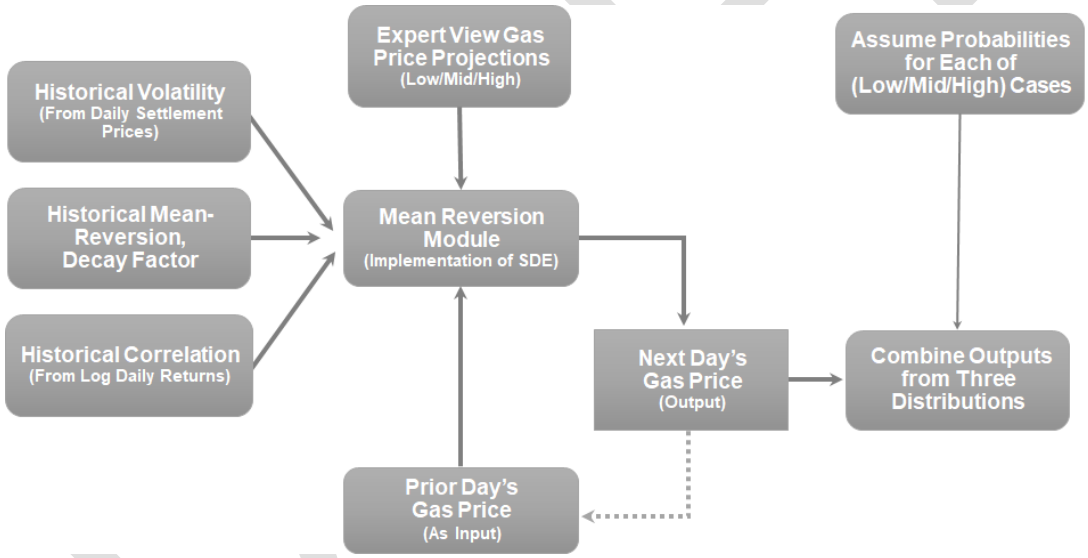
DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

The steps involved in the development of gas stochastics are:

- As the first step, Siemens PTI develops the long-term fundamental forecast of Henry hub and several other gas basis points prices (using the GPCM model). The probability distributions are developed around this fundamental forecast.
- From historical data sets, the volatility parameter is calculated using the daily settled prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical daily settled prices.
- For more than one gas basis point prices, the appropriate correlations are also calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below.

Exhibit 64: Gas Stochastics Development Process

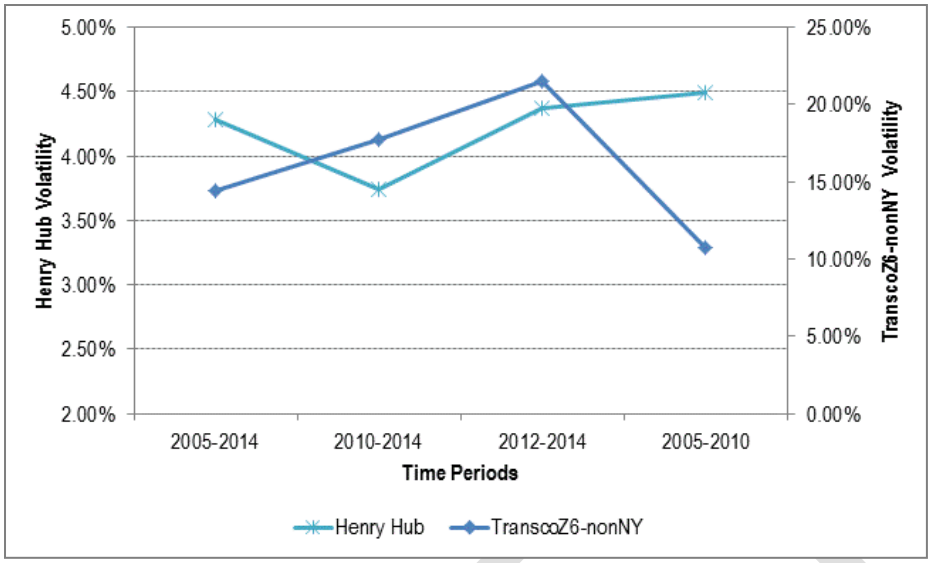


Source: Siemens PTI

- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time periods are considered. For example, for the first 3 forecast years, volatility calculated from the past 30 months price data will be used. For years 4-8, volatility calculated from the past 5 years will be used. Beyond that time period, the past 10-year historical volatility will be used.
- For example, Exhibit 65 below shows the volatilities for Henry hub and a gas point in the Northeast (for illustration), for different historical time periods.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 65: Henry Hub and TranscoZ6-nonNY Volatility



Source: Siemens

The long-term fundamental forecast for each month in the forecast time period will be treated as the mean-reverting level in this process.

B.3 Coal Stochastics

Siemens PTI develops coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins.

These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters.

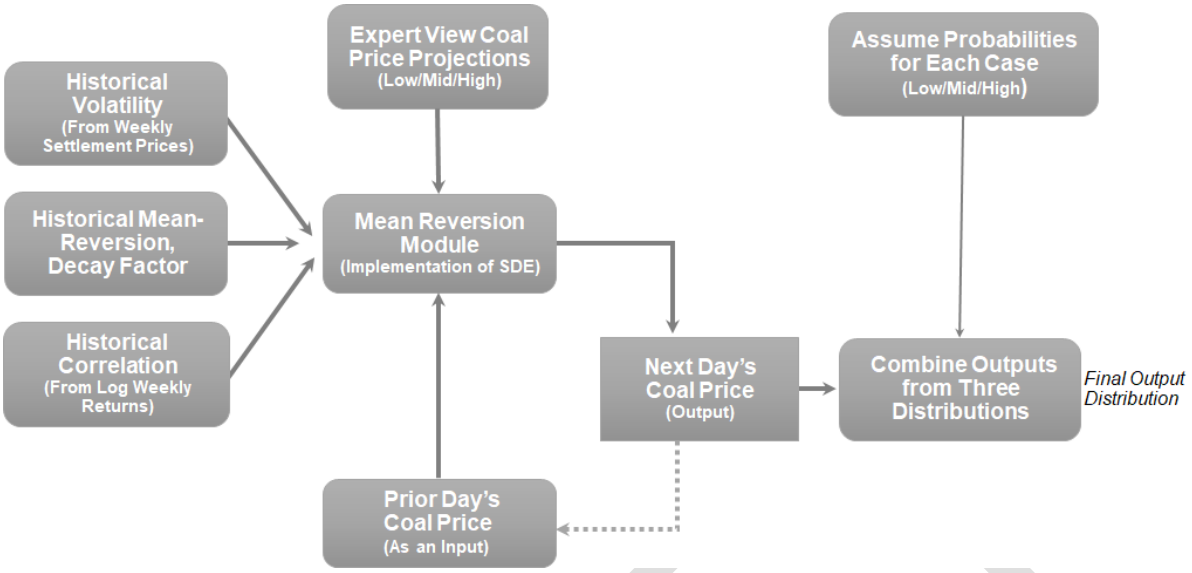
It is to be noted that majority of coal contracts in the U.S. are bilateral and only about 20% are traded in NYMEX. The historical data set which is used to calculate the parameters comprise of the traded data reported in NYMEX, which is weekly.

The methodology involved in the distribution of stochastic coal prices is exactly similar to natural gas stochastics.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 66: Process for Coal Price Stochastic



Source: Siemens

The steps involved in the development of coal basin price stochastics are:

- As the first step, Siemens PTI develops the long-term fundamental forecast of each of the coal basins. The probability distributions are developed around these fundamental forecasts.
- From historical data sets, the volatility parameter is calculated using the weekly prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations are calculated from the historical data.

B.4 CO_2 Stochastics

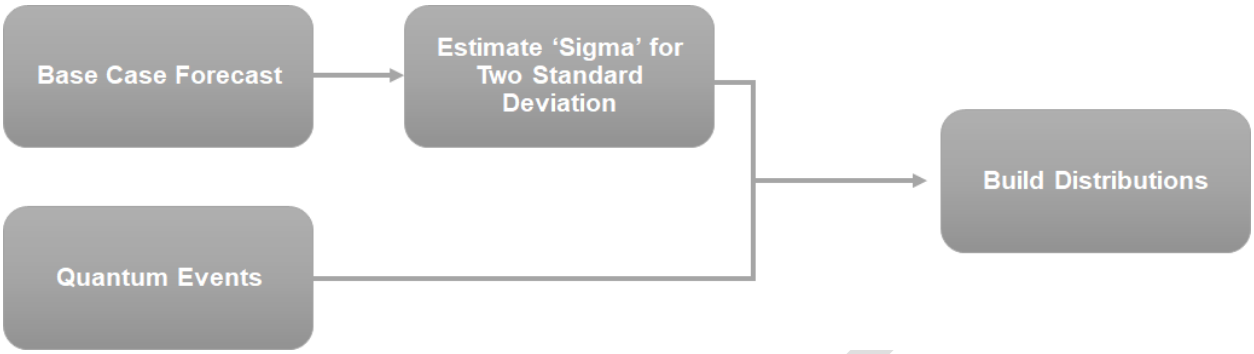
Siemens PTI develops uncertainty distributions around CO_2 compliance costs, which will be used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop CO2 costs distributions, unlike the previous variables, is based on the "expert-opinion" based projections. There are no historical data sets to estimate the parameters for developing CO_2 costs distributions. The views of the internal subject matter experts (Siemens PTI's) are taken into consideration. The exhibit below shows the high-level methodology for developing stochastic distributions when the historical data is not available.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 67: Technique to Develop CO_2 Costs Distributions



Source: Siemens PTI

Given below are the steps involved in this process:

- Siemens PTI's environmental team develops a reference case (base case) forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases are also developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques (tools), the standard deviation values are calculated.
- The reference case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference projections. This underlying distribution captures the "quantum" events that can happen in the market.
- The distributions are then adjusted to incorporate probabilities such as "the probability of a CO_2 program not taking effect", "greater chance of a nation-wide CO_2 regime starting in, say 2022" etc.
- Separate distributions are developed for national CO_2 costs, California CO_2 costs and RGGI prices, which are then applied to the respective states.

B.5 Gas-Coal-CO_2 prices feedback (Cross-Commodity Correlations)

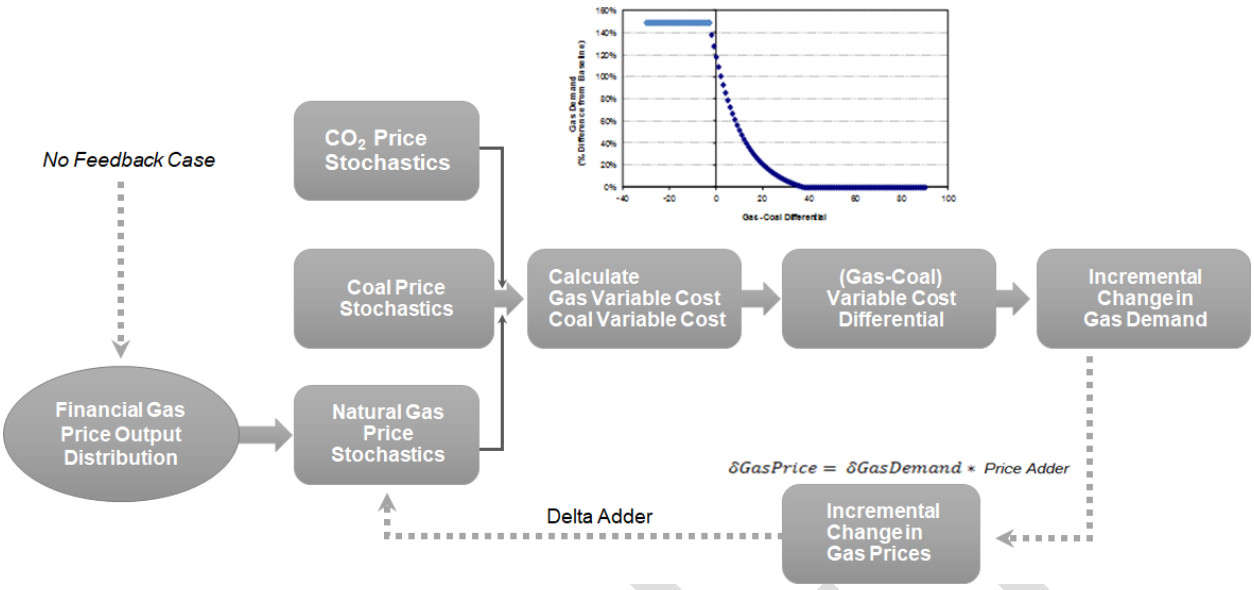
Siemens PTI has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal and CO_2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback to gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 68: Cross Commodity Correlations



Source: Siemens PTI

- Siemens PTI has performed some fundamental analyses to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.
- For each iteration, the dispatch cost of gas and coal is calculated from the fuel stochastics and CO2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from previous year is adjusted to reflect the corresponding change in demand.
  - Adjustment can happen in both directions
- A gas price delta is then calculated based on the defined gas demand – price relationship developed.
- This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

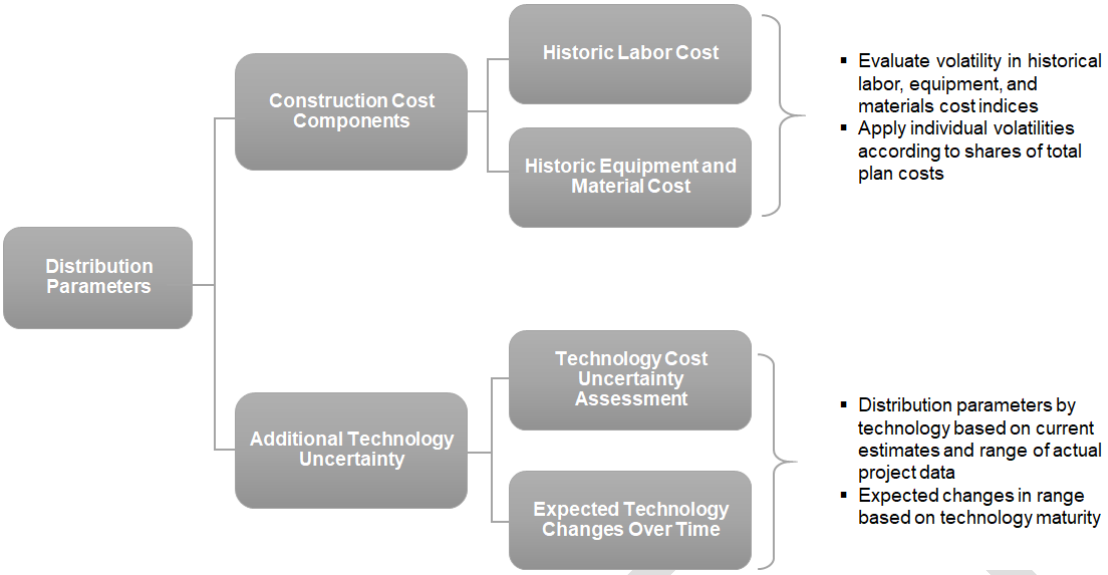
B.6 Capital Cost Stochastics

Siemens PTI develops the uncertainty distributions for the cost of new entry units by technology types, which will be used in the AURORA dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Exhibit 69: Capital Costs Stochastics Methodology



Source: Siemens PTI

The methodology of develop the capital cost distributions is a two-step process:

B.7 Step 1: Parametric Distribution:

Siemens PTI's subject matter experts provide a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts are also developed.

The plant costs are broken down by Equipment, Materials, Labor & Others. Historical data (from Handy-Whitman Index) is used to estimate mean price changes and volatilities in these cost categories.

Suitable weights are allocated to each of these 4 categories. The weighted average of the historical mean and volatilities are then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference forecast.

B.8 Step 2: Quantum Distribution:

This step captures the additional uncertainty associated with each technology. It also factors-in the learning curve effects, improvements in technology over time and other "uncertain" events. The expert-opinion based high and low cases are treated as 1 standard deviation from the mean. With this assumption, the variance values are calculated.

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

To come with probability distributions, a log-normal distribution is assumed. This distribution is combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.

Unrestricted

Appendix C: Terms and Definitions

Advisory Council

The OUC EIRP Advisory Council is 12-member volunteer group – nominated by elected City and County Commissioners from Orange and Osceola counties and the Cities of Orlando and St. Cloud – who represent a cross-section of our community. The role of the Advisory Council – as advisors, educators and a connection point to the communities they represent – is to serve as a voice for all stakeholder groups. These groups include residential customers, fixed income groups, community partners, environmental groups, OUC program participants, and Orange and Osceola County residents.

Affordability

An electric system's ability to produce and deliver energy at an affordable cost with minimal price fluctuations.

Siemens PTI uses metrics related to the portfolio costs of generation and transmission, including fixed cost recovery, and the uncertainty of portfolio costs to measure each Candidate Portfolio for this Attribute.

Attributes

A quality or characteristic of a portfolio. For the purpose of the EIRP, the four Attributes (Affordability, Reliability, Resiliency, Sustainability) are the primary objectives used to evaluate the performance of all Candidate Portfolios.

Calibration Portfolio

This portfolio serves as a business-as-usual (BAU) outlook of expected market conditions and expected load. The Calibration Portfolio also serves as a benchmark to measure the performance of other portfolios relative to a baseline.

Candidate Portfolios

For the purpose of the EIRP, Candidate Portfolios are developed to be tested against the four Attributes for potential selection as OUC's resource strategy.

CO_2 Offsets to Meet Net Zero CO_2 Goals

CO_2 offsets were calculated from the use of electric vehicles to potentially offset any CO_2 emissions from electricity generation. The electric vehicles forecast is consistent with OUC's 2025 strategic plan. Although other types of offsets are available such as market purchases of credit and reforestation, no other offsets are used for the purpose of this EIRP.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Conditions

Conditions represent external scenarios that influence and affect the financial, technical and operational environments in which future generation resources should be considered including technology advancements and regulatory changes.

Demand (Peak Demand)

The rate of electricity consumption over any instance. It is typically measured in kilowatts (kW) or megawatts (MW).

Deterministic Modeling

A deterministic model is one where variables are uniquely determined by parameters in the model[28]. In other words, the analysis or simulation is conducted with one set of inputs and one set of outputs. A deterministic model does not capture the uncertainty inherent in forecasts.

Dispatchable Generation

Dispatchable generation refers to a type of generation that can be controlled to balance real-time electricity supply and demand. Most conventional power sources such as coal or natural gas power plants are dispatchable in order to meet the always changing electricity demands of the population. In contrast, many renewable energy sources are intermittent and non-dispatchable, such as wind power or solar power which can only generate electricity while their primary resource is available[29].

Energy

Energy is defined as the electricity consumption by consumers over a period of time. It is typically measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

Battery Energy Storage Systems

While battery energy storage cannot generate electricity, energy can be stored and later reconverted to electricity on demand. For the purpose of the EIRP, battery energy storage systems store energy from solar arrays or the electric grid and provide energy to consumers when needed. Battery energy storage systems can be used to improve the dispatchability of solar or wind energy systems.

Net Zero CO_2

Net Zero CO_2 refers to a condition of zero CO_2 emissions from electric generation net of any recognized offsets such as avoided CO_2 emissions from electric vehicles.

---

[28] Renard, Philippe, et al. "Stochastic versus Deterministic Approaches." Environmental Modelling, 2013, pp. 133–149., doi:10.1002/9781118351475.ch8.

[29] https://energyeducation.ca/encyclopedia/Dispatchable_source_of_electricity#cite_note-2

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Pathways

Methodologies and/or strategies to achieve the EIRP objective to reach the Net Zero CO_2 goal by 2050. Pathways are used to develop Candidate Portfolios. Examples of pathways used in the EIRP are:

- *Net Zero CO_2 by 2050* – Both CO_2-free and CO_2-generating resources are used.
- *100% Renewable Energy by 2050 w/ Intermediate Targets* – Meets the City of Orlando's target of 100% renewable energy by 2050 with intermediate benchmarks for OUC of 50% Renewable Energy Generation by 2030 and 75% Renewable Energy Generation by 2040.
- *100% Renewable Energy by 2050 w/ Intermediate Targets including Nuclear* – Same as Pathway 2 but with Nuclear and Biomass included as potential resources.
- *100% Net Zero CO_2 by 2050 (OUC+FL)* – Same as Pathway 1 but with all Florida Utilities required to offset their CO_2.
- *Stanton Plant Retirement (Stanton Phase-Out)* – Follows the first unaffiliated Synapse report (circa 2018) that posits the retirement of the Stanton 1 coal unit and the Stanton 2 coal unit with only renewable energy and storage capacity allowed to backfill.

Reliability

An electric system's ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance.

Each portfolio is designed to meet or exceed the Reliability requirement of 100% energy sufficiency as an islanded system under expected deterministic conditions. All portfolios meet this minimum threshold. Siemens PTI uses unserved energy and technological diversity as metrics to measure the Reliability of Candidate Portfolios.

Resiliency

An electric system's ability to adapt to uncontrollable events – such as weather extremes (hurricanes, major storms, heat waves, cloud cover, other extreme weather events) – maintain physical and cyber security, and quickly bounce back following an interruption.

Siemens PTI uses scenario analysis simulating system shocks such as hurricanes and gas pipeline disruptions and metrics related to unserved energy to measure each portfolio for this Attribute.

Stochastic Modeling

A stochastic model attempts to capture the uncertainty inherent in forecasts. Whereas a deterministic model has one set of inputs and one set of outputs for each variable, a stochastic model may have a range of inputs and outputs for each variable. For the purpose of the EIRP, Siemens PTI uses a stochastic modeling approach that simulates a broad range of market conditions, capturing the uncertainty in electricity demand, fuel prices, emissions prices, and the capital costs for generating technologies.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Sustainability

An electric system's ability to produce energy in a way that proactively reduces pollution and impacts on the surrounding ecosystem.

For the purpose of the EIRP, Sustainability is synonymous with environment stewardship through the use of "clean" generating technologies.

Synapse Study (August 1, 2018)

A third-party study provided by the First Fifty Coalition that details how the Stanton coal plant could be closed in a short time frame. Synapse proposes to retire one Stanton Coal unit at the end of 2020 and a second Stanton coal unit as soon as possible thereafter. The Synapse report was revised in June 2020.

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Appendix D: Existing Unit Specifications and Model Topography

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO_2)	Emission Rates lbs/MMBtu (SOx)	Emission Rates lbs/MMBtu (Nox)	Resource Location (for modeling)
OUC Assets	Stanton 1	441.0	441.0	68.5%	302.1	302.1	25%	75.4	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	OUC GEN
	Stanton 1 (effective May 1, 2020)	453.0	453.0	68.5%	310.3	310.3	24%	75.4	Coal	Jul-87	n/a	9,200	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	OUC GEN
	Stanton 2	453.0	453.0	75.0%	339.8	339.8	24%	82.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	OUC GEN
	Stanton 2 (effective Dec 1, 2020)	463.0	463.0	75.0%	347.3	347.3	24%	82.5	Coal	Jun-96	n/a	9,050	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	OUC GEN
	Stanton A Owned (1x1)	230.0	235.0	80%	184.0	188.0	66%	124.0	Natural Gas	Oct-03	n/a	7000 / 8000	40	8	360	360	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton A PPA (2x1)	332.8	340.0	80%	266.2	272.0	54%	148.0	Natural Gas	Oct-03	12/31/2031	6800 / 7500	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton A PPA (DF)	107.6	110.0	80%	86.0	88.0	36%	32.0	Natural Gas	Oct-03	12/31/2031	12,000	2	1	120	120	4.6%	7.0%	119	0.0000	0.0180	OUC GEN
	Stanton B CC + PA	271.1	285.0	100%	271.1	285.0	53%	150.0	Natural Gas	Feb-10	n/a	7,400	36	8	360	360	4.6%	7.0%	119	0.0000	0.0050	OUC GEN
	Stanton B Duct-Burner	39.9	42.0	100%	39.9	42.0	0%	0.0	Natural Gas	Feb-10	n/a	9,350	n/a	n/a	30	30	4.6%	7.0%	119	0.0000	0.0050	OUC GEN
	Indian River A	30.2	35.0	48.8%	14.7	17.1	63%	10.7	Natural Gas	Jun-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1300	OUC GEN
	Indian River B	30.2	35.0	48.8%	14.7	17.1	63%	10.7	Natural Gas	Jul-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1000	OUC GEN
	Indian River C	103.2	110.0	79%	81.5	86.9	32%	27.7	Natural Gas	Aug-92	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0720	OUC GEN
	Indian River D	103.2	110.0	79%	81.5	86.9	32%	27.7	Natural Gas	Oct-92	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0650	OUC GEN
	St Lucie	60.0	62.0	100%	60.0	62.0	100%	60.0	Nuclear	Jun-83	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	OUC GEN
	C. D. McIntosh Jr. 3	352.1	360.0	40%	140.8	144.0	50%	72.0	Coal	Sep-82	12/1/2024	10,163	168	60	180	180	7.9%	9.6%	205	0.0520	0.0540	OUC GEN
	Florida Municipal Solar PV1-3	223.5	0.0	48%	54.0	0.0	n/a	n/a	Solar	Jun-20	6/30/2050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Invenergy Kissimmee	74.5	0.0	100%	37.3	0.0	n/a	n/a	Solar	Dec-22	12/31/2042	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Invenergy Sabal Palm	74.5	0.0	100%	37.3	0.0	n/a	n/a	Solar	Dec-23	12/31/2043	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Stanton Solar Farm	6.0	0.0	100%	3.0	0.0	n/a	n/a	Solar	n/a	8/31/2030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Stanton Solar PPA (Ksionek)	8.9	0.0	100%	4.5	0.0	n/a	n/a	Solar	n/a	8/31/2037	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO_2)	Emission Rates lbs/MMBtu (SOx)	Emission Rates lbs/MMBtu (Nox)	Resource Location (for modeling)
	Landfill Gas (CBI @ Drury)	9.0	9.0	100%	9.0	9.0	n/a	n/a	LFG	n/a	10/31/2035	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Landfill Gas PPA (Broward)	6.0	6.0	100%	6.0	6.0	n/a	n/a	LFG	n/a	3/31/2036	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
	Landfill Gas PPA (Charlotte)	2.6	2.6	100%	2.6	2.6	n/a	n/a	LFG	n/a	9/30/2031	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	OUC GEN
Non-OUC FMPA Assets	Cane Island 1 - CT	35.0	38.0	100%	35.0	38.0	30%	0.0	Natural Gas	n/a	n/a	9,000	6	4	308	308	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 2 - CC	109.0	113.0	100%	109.0	113.0	30%	33.9	Natural Gas	1995	n/a	7,910	6	4	151	151	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 3 - CC	240.0	250.0	100%	240.0	250.0	30%	75.0	Natural Gas	2002	n/a	7,400	6	4	335	335	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	Cane Island 4 - CC	300.0	310.0	100%	300.0	310.0	30%	93.0	Natural Gas	2011	n/a	7,400	6	4	415	415	4.6%	7.0%	119	0.0000	0.0247	FMPA KUA GEN
	St Lucie	9.0	9.0	100%	9.0	9.0	90%	8.1	Nuclear	n/a	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	FMPA KUA GEN
	Indian River A	30.2	35.0	51.2%	15.4	17.9	63%	11.3	Natural Gas	Jun-89	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1300	OUC GEN
	Indian River B	30.2	35.0	51.2%	15.4	17.9	63%	11.3	Natural Gas	n/a	n/a	13,200	1	1	300	300	11.2%	3.9%	119	0.0000	0.1000	OUC GEN
	Indian River C	103.2	110.0	21%	21.7	23.1	32%	35.0	Natural Gas	n/a	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0720	OUC GEN
	Indian River D	103.2	110.0	21%	21.7	23.1	32%	35.0	Natural Gas	n/a	n/a	12,400	1	1	600	600	7.6%	3.9%	119	0.0000	0.0650	OUC GEN
	Larsen 2	10.0	14.0	100%	10.0	14.0	30%	4.2	Natural Gas	n/a	n/a	15,500	6	4	114	114	4.6%	7.0%	119	0.0000	0.0247	LAKELAND GEN
	Larsen 3	9.0	13.0	100%	9.0	13.0	30%	3.9	Natural Gas	n/a	n/a	15,500	0	0	105	105	21.4%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	Larsen 8	105.0	124.0	100%	105.0	124.0	30%	37.2	Natural Gas	n/a	n/a	9,000	0	0	166	166	21.4%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	C. D. McIntosh Jr. 3	352.1	360.0	60%	211.2	216.0	50%	108.0	Coal	n/a	12/1/2024	10,163	168	60	180	180	7.9%	9.6%	205	0.0520	0.0540	LAKELAND GEN
	C. D. McIntosh Jr. 5	338.0	354.0	100%	338.0	354.0	30%	106.2	Natural Gas	n/a	n/a	7,400	6	4	474	474	4.6%	7.0%	119	0.0000	0.0247	LAKELAND GEN
	LAK MAC GT2	115.0	125.0	100%	115.0	125.0	30%	37.5	Natural Gas	Apr-20	n/a	11,700	4	8	670	670	2.5%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	McIntosh Diesels	5.0	5.0	100%	5.0	5.0	0%	0.0	Diesel	n/a	n/a	10,696	0	0	27	27	4.0%	3.8%	162	0.6505	0.0327	LAKELAND GEN
	McIntosh GT1	16.0	19.0	100%	16.0	19.0	45%	8.6	Natural Gas	n/a	n/a	15,000	6	4	102	102	8.1%	3.9%	119	0.0000	0.0112	LAKELAND GEN
	Winston Diesels	50.0	50.0	100%	50.0	50.0	0%	0.0	Diesel	n/a	n/a	9,000	0	0	268	268	4.0%	3.8%	162	0.6505	0.0327	LAKELAND GEN
	Oleander 5	157.0	157.0	100%	157.0	157.0	30%	47.1	Natural Gas	n/a	n/a	11,500	0	0	841	841	7.9%	9.6%	119	0.0000	0.0112	FMPA EAST GEN
	St Lucie 2	48.0	50.0	100%	48.0	50.0	100%	48.0	Nuclear	n/a	n/a	10,500	n/a	n/a	n/a	n/a	3.8%	8.3%	n/a	n/a	n/a	FMPA EAST GEN
	Stanton 1	441.0	441.0	31.5%	112.0	112.0	31%	34.7	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	FMPA EAST GEN + FMPA WEST GEN
	Stanton 1 (effective May 1, 2020)	453.0	453.0	31.5%	112.0	112.0	31%	34.7	Coal	Jul-87	n/a	9,806	168	60	120	120	7.7%	9.6%	202	0.1200	0.2500	FMPA EAST GEN + FMPA WEST GEN
	Stanton 2	453.0	453.0	25.0%	102.0	102.0	27%	27.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	FMPA EAST GEN + FMPA WEST GEN

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Capacity Holder	Plant Name	Summer Capacity (MW)	Winter Capacity (MW)	Entity Share of Capacity (%)	Summer Capacity by Entity Share (MW)	Winter Capacity by Entity Share (MW)	Minimum Capacity (%)	Entity Share Minimum Capacity (MW)	Fuel Type	COD	End Date	Heat Rate	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp Up Rate (MW/Hour)	Ramp Down Rate (MW/Hour)	Average Forced Outage	Average Maintenance Rate (%)	Emission Rates lbs/MMBtu (CO_2)	Emission Rates lbs/MMBtu (SOx)	Emission Rates lbs/MMBtu (Nox)	Resource Location (for modeling)
	Stanton 2 (effective Dec 1, 2020)	463.0	463.0	25.0%	102.0	102.0	27%	27.5	Coal	Jun-96	n/a	9,184	168	60	120	120	7.7%	9.6%	202	0.1100	0.1400	FMPA EAST GEN + FMPA WEST GEN
	Stanton A (1x1) FMPA-Owned	230.0	235.0	20%	46.0	47.0	66%	31.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Stanton A (2x1) FMPA-PPA	332.8	340.0	20%	66.6	68.0	54%	37.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Stanton A (DF) FMPA-PPA	107.6	110.0	20%	21.5	22.0	36%	8.0	Natural Gas	n/a	n/a	7,400	8	8	720	720	4.6%	7.0%	119	0.0000	0.0180	FMPA EAST GEN
	Florida Municipal Solar PV1-3	223.5	0.0	52%	58.1	0.0	n/a	n/a	Solar	Jun-20	6/30/2050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	FMPA EAST GEN
	Stock Island CT 1	19.0	19.0	100%	19.0	19.0	0%	0.0	Diesel	n/a	n/a	10,607	0	0	154	154	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 2	16.0	16.0	100%	16.0	16.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	130	130	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 3	14.0	14.0	100%	14.0	14.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	114	114	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island CT 4	46.0	46.0	100%	46.0	46.0	0%	0.0	Diesel	n/a	n/a	9,119	0	0	246	246	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island EP2	2.0	2.0	100%	2.0	2.0	0%	0.0	Diesel	n/a	n/a	10,607	0	0	11	11	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Stock Island MSDs + EP2	18.0	18.0	100%	18.0	18.0	0%	0.0	Diesel	n/a	n/a	10,000	0	0	86	86	4.0%	3.8%	162	0.6505	0.0327	FMPA EAST GEN
	Treasure Coast Energy Center	300.0	310.0	100%	300.0	310.0	30%	93.0	Natural Gas	n/a	n/a	7,600	6	4	415	415	4.6%	7.0%	119	0.0000	0.0247	FMPA EAST GEN
	Tom Smith CC	30.0	30.0	100%	30.0	30.0	48%	14.4	Natural Gas	n/a	12/31/2025	10,244	5	6	40	40	4.6%	7.0%	119	0.0000	0.0247	LAKE WORTH GEN
	Tom Smith GT	27.0	27.0	100%	27.0	27.0	0%	0.0	Diesel	n/a	12/31/2025	12,460	0	0	145	145	4.0%	3.8%	162	0.6505	0.0327	LAKE WORTH GEN
	Tom Smith 3	27.0	27.0	100%	27.0	27.0	27%	7.3	Natural Gas	n/a	12/31/2025	12,537	6	6	36	36	13.1%	3.9%	119	0.0000	0.0247	LAKE WORTH GEN
	St. Lucie 2	20.0	20.0	100%	20.0	20.0	100%	20	Nuclear	n/a	12/31/2025	10,500	n/a	n/a	n/a	n/a	3.80%	8.30%				LAKE WORTH GEN

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Appendix E: List of Abbreviations

Abbreviation	Definition
AACE	American Association of Cost Engineers
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BAU	Business-As-Usual
BEV	Battery Electric Vehicles
CAISO	California Independent System Operator
CAPP	Central Appalachian
CCGT	Combined cycle gas turbines
CDD	Cooling Degree Days
CIL	Capacity Import Limit
CT	Cycle Combustion Turbines
DEF	Duke Energy Florida
DG	Distributed Solar Generation
DR	Demand Response
EE	energy efficiency
EIA	U.S. Energy Information Administration
EIRP	Electric Integrated Resource Plan
EPA	Environmental Protection Agency
EV	Electric Vehicle
FEECA	Florida Energy Efficiency and Conservation Act
FMPA	Florida Municipal Power Agency
FMPP	Florida Municipal Power Pool
FPL	Florida Power and Light
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GHG	Green House Gas
GPCM	Gas Pipeline Competition Model
HDD	Heating Degree Days
HRSG	Heat Recovery
HUM	Humidity
ILB	Illinois Basin
IPP	independent power producers
ISO	Independent System Operator (Organization for Standardization)
ITC	Investment Tax Credit

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

Abbreviation	Definition
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
ORNL	Oak Ridge National Labs
PHEV	Plug-In Hybrid Electric Vehicles
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PRB	Powder River Basin
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SERC	SERC Reliability Corporation
SMR	Small Modular Reactor
TECO	Tampa Electric Company
UCAP	Unforced Generation Capacity
WACC	Weighted Average Cost of Capital

DRAFT

Copyright © 2020 Siemens Industry, Inc. All Rights Reserved.
Unrestricted

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 9

DOE 4.8.26 LETTER

Department of Energy
Washington, DC 20585

April 8, 2026

Mr. Clint P. Bullock
General Manager and Chief Executive Officer
Orlando Utilities Commission
100 W. Anderson St.
Orlando, FL 32801

Re: Information Request for Stanton Energy Center

Mr. Bullock:

The U.S. Department of Energy (DOE) is responsible for ensuring the adequacy, reliability, and security of energy supplies throughout the United States. This mission includes oversight of energy production, transmission, and distribution infrastructure; coordination with federal, state, and regional entities; and the collection of information necessary to identify and address risks to the national energy supply. DOE carries out this work to protect the public interest and support the long-term resilience of the Nation's energy systems.

The Trump Administration and Secretary Wright have prioritized ensuring reliable electric supplies. Key sectors in the modern economy of our great Nation depend on reliable electricity, including hospitals and emergency services, transportation, communications, and industrial production. President Trump has 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."[1] Disruptions to electric supply, even of short duration, can have serious and cascading consequences for public safety, economic activity, and national security. Therefore, DOE seeks to understand the capacity, condition, and operational status of electric supplies across the country, including the potential retirement of existing generation resources, to ensure that the Nation's electric

[1] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

grid will meet the current and projected demand for manufacturing, re-industrialization, and technological innovation, among other needs.

DOE requests that you complete and return the questions attached as Exhibit 1 within 14 calendar days. You may designate information as confidential, where appropriate, and DOE will handle any such information in accordance with applicable laws and regulations. Please ensure that responses are accurate and complete. If you have any questions, you may reach out to the Office of Cybersecurity, Energy Security, and Emergency Response (CESER) at askCR@hq.doe.gov.

DOE appreciates your attention to this important request, which supports the reliability and security of the bulk power system.

Sincerely,

Alex Fitzsimmons
Under Secretary of Energy (Acting)
Director, Office of Cybersecurity, Energy Security & Emergency Response

Exhibit 1

1. Please identify the full legal name of the generating facility, its physical address, the Facility ID Number, and also the owner and operator names.

2. Please identify the Generator/Unit Information for each unit at the facility, including the Generator/Unit Name, the types of fuel it uses, whether it is dual fuel, its nameplate capacity in MW and its operating status. For example, an acceptable response would be Unit 1, coal, not dual fuel, 125MW, down for periodic maintenance.

3. Please explain how the unit is currently used (e.g. peaking, baseload, backup), its planned retirement date (if applicable), whether retirement has been previously accelerated or delayed, the reasons for the planned retirement, and the relevant local, state, or federal laws related to retirement.

4. If you were at some previous point considering a retirement or sale of the facility and are now considering delaying retirement or sale of the unit please describe the circumstances.

5. If you are considering a retirement or sales of the unit, please identify and explain with detail and particularity:

    a. If the facility is not in an ISO/RTO market how is a loss of generation from the planned retirement expected to be replaced?

    b. Are there any relevant local, state, or federal laws regarding generation from the type of facility at issue?

    c. Is it possible for the facility to operate on a going forward basis without conflicting with federal, state, or local laws? If so, for how long and under

what operating conditions?

d. Would continued operation of the facility/units planned for retirement result in significantly increased costs for consumers? If yes, how? Would these costs be offset by increased reliability?

6. If you are considering a conversion to natural gas, please identify the planned conversion date and general timeline, explain whether the conversion will result in units maintaining or increasing nameplate capacity and/or an increase in capacity factor, and whether there will be a result in cost savings for customers.

7. If you are considering a conversion to natural gas, please explain with detail and particularity the actions being taken to minimize the length of outage for the conversion (e.g. use of existing turbines), explain whether external factors (e.g. laws, company policy) are driving the conversion, and any other relevant information.

8. Please explain with detail and particularity:

   a. Are there any major operating limitations for any units at the facility;

   b. Are there any safety considerations with continued operations; and

   c. Are there any workforce, fuel availability, contractual, or permitting complications at issue?

9. Regarding each generating facility footprint, please identify and explain with detail and particularity:

   a. The Balancing Authority;

b. The Reliability Coordinator;

c. The name of the state utility regulatory commission and its relevant regulatory authority as it relates to the facility; and

d. Any other relevant parties.

10. If the facility is not in an ISR/RTO market, please explain with detail and particularity, how energy and capacity, as applicable, from the facility is purchased. Are there any unique requirements/laws that affect the sale of energy and/or capacity from the facility?

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 10

YOUTUBE, GOVERNOR DESANTIS SIGNS LAW TO PROTECT FLORIDIANS FROM SUBSIDIZING DATA CENTERS

Governor DeSantis Signs Law to Protect Floridians from Subsidizing Data Centers

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 11

FPL 2026 TYSP

Ten Year Power Plant Site Plan
2026 – 2035

(This page is intentionally left blank.)

Ten Year Power Plant Site Plan

2026-2035

Submitted To:

Florida Public
Service Commission

April 2026

Table of Contents

List of Figures, Tables, and Maps iii

List of Schedules iv

Overview of the Document 1

List of Abbreviations Used in Forms 3

Executive Summary 5

Chapter I. Description of Existing Resources 19

I.A FPL System: 21

I.A.1. Description of Existing Resources 21
I.A.2. FPL - Owned Resources 21
I.A.3. FPL - Capacity and Energy Power Purchases 28
I.A.4. FPL – Demand-Side Management (DSM) 32
I.A.5. Existing Generating Units in FPL's Service Area 32

Chapter II. Forecast of Electric Power Demand 44

II.A. Overview of the Load Forecasting Process 46
II.B. Customer Forecasts 47
II.C. Energy Sales Forecasts 48
II.D. Net Energy for Load (NEL) 52
II.E. System Peak Forecasts 53
II.F. Hourly Load Forecast 55
II.G. Uncertainty 56
II.H. DSM 56

Chapter III. Projection of Incremental Resource Additions 72

III.A. FPL's Resource Planning 74
III.B. Projected Incremental Resource Changes in the Resource Plan 84
III.C. Discussion of the Resource Plan and Issues Impacting Resource Planning Work 84
III.D. Demand-Side Management (DSM) 93
III.E. Transmission Plan 96
III.F. Renewable Resources and Storage Technology 181
III.G. Fuel Mix and Fuel Price Forecasts 197

Chapter IV. Environmental and Land Use Information 403

IV.A. Protection of the Environment 405
IV.B. Environmental Organization Contributions 406
IV.C. Environmental Communication and Facilitation 407
IV.D. Environmental Policy 407

IV.E. Environmental Management 409
IV.F. Environmental Assurance Program 409
IV.G. Preferred and Potential Sites 410

Chapter V. Other Planning Assumptions & Information 417

Appendix. Preferred and Potential Solar Site Descriptions and Maps 428

A. Site Descriptions, Environmental, and Land Use Information 429

B. Preferred Sites 432
1. Preferred Site #1 – Big Brook Solar Energy Center, Calhoun County 433
2. Preferred Site #2 – Boardwalk Solar Energy Center, Collier County 438
3. Preferred Site #3 – Flatford Solar Energy Center, Manatee County 443
4. Preferred Site #4 – Goldenrod Solar Energy Center, Collier County 448
5. Preferred Site #5 – Mallard Solar Energy Center, Brevard County 453
6. Preferred Site #6 – Mare Branch Solar Energy Center, DeSoto County 458
7. Preferred Site #7 – Price Creek Solar Energy Center, Columbia County 463
8. Preferred Site #8 – Swamp Cabbage Solar Energy Center, Hendry County 468
9. Preferred Site #9 – Clover Solar Energy Center, St. Lucie County 473
10. Preferred Site #10 – North Orange Solar Energy Center, St. Lucie County 478
11. Preferred Site #11 – Sand Pine Solar Energy Center, Calhoun County 483
12. Preferred Site #12 – Sea Grape Solar Energy Center, St. Lucie County 488
13. Preferred Site #13 – Big Brook Battery Storage Center, Calhoun County 493
14. Preferred Site #14 – Cedar Trail Battery Storage Center, Baker County 498
15. Preferred Site #15 – Nature Trail Battery Storage Center, Baker County 503
16. Preferred Site #16 – North Orange Battery Storage Center, St. Lucie County 508
17. Preferred Site #17 – Norton Creek Battery Storage Center, Madison County 513
18. Preferred Site #18 – Sand Pine Battery Storage Center, Calhoun County 518
19. Preferred Site #19 – Thomas Creek Battery Storage Center, Nassau County 523
20. Preferred Site #20 – Lansing Smith Battery Storage Center, Bay County 528

21. Preferred Site #21 – Clover Battery Storage Center, St. Lucie County 533
22. Preferred Site #22 – Fawn Battery Storage Center, Martin County 538
23. Preferred Site #23 – Putnam Battery Storage Center, Putnam County 543
24. Preferred Site #24 – Sea Grape Battery Storage Center, St. Lucie County 548
25. Preferred Site #25 – White Tail Battery Storage Center, Martin County 553
26. Preferred Site #26 – Spanish Moss Solar Energy Center, St. Lucie County 558
27. Preferred Site #27 – County Line Solar Energy Center, Charlotte/ DeSoto County 563
28. Preferred Site #28 – Hendry Solar Energy Center, Hendry County 568
29. Preferred Site #29 – Indrio Solar Energy Center, St. Lucie County 573
30. Preferred Site #30 – Middle Lake Solar Energy Center, Madison County 578
31. Preferred Site #31 – Saddle Solar Energy Center, DeSoto County 583
32. Preferred Site #32 – Tangelo Solar Energy Center, Okeechobee County 588
33. Preferred Site #33 – Wood Stork Solar Energy Center, St. Lucie County 593
34. Preferred Site #34 – Catfish Solar Energy Center, Okeechobee County 598
35. Preferred Site #35 – Cocoplum Solar Energy Center, Hendry County 603
36. Preferred Site #36 – Hardwood Hammock Solar Energy Center, Walton County 608
37. Preferred Site #37 – Joshua Creek Solar Energy Center, DeSoto County 613
38. Preferred Site #38 – Maple Trail Solar Energy Center, Baker County 618
39. Preferred Site #39 – Myakka Solar Energy Center, St. Lucie County 623
40. Preferred Site #40 – Pinecone Solar Energy Center, Calhoun County 628
41. Preferred Site #41 – Vernia Solar Energy Center, Indian River County 633
42. Preferred Site #42 – Blue Heron Battery Storage Center, Hendry County 638
43. Preferred Site #43 – Green Pasture Battery Storage Center, Charlotte County 643
44. Preferred Site #44 – Orange Blossom Battery Storage Center, Indian River County 648
45. Preferred Site #45 – Sawgrass Battery Storage Center, Hendry County 653

46. Preferred Site #46 – Swamp Cabbage Battery Storage Center, Hendry County 658
47. Preferred Site #47 – Terrill Creek Battery Storage Center, Clay County 663
48. Preferred Site #48 – Indrio Battery Storage Center, St. Lucie County 668
49. Preferred Site #49 – Maple Trail Battery Storage Center, Baker County 673
50. Preferred Site #50 – Monarch ACES Pilot Battery Storage Center, Martin County 678
51. Preferred Site #51 – Monarch Battery Storage Center, Martin County 683
52. Preferred Site #52 – Swallowtail Battery Storage Center, Walton County 688
53. Preferred Site #53 – Union Springs Battery Storage Center, Union County 693
54. Preferred Site #54 – Beachland Solar Energy Center, Indian River County 698
55. Preferred Site #55 – Bromeliad Solar Energy Center, Collier County 703
56. Preferred Site #56 – Honeybee Solar Energy Center, Collier County 708
57. Preferred Site #57 – Inlet Solar Energy Center, Indian River County 713
58. Preferred Site #58 – Sand Gully Solar Energy Center, DeSoto County 718
59. Preferred Site #59 – Shores Solar Energy Center, Indian River County 723
60. Preferred Site #60 – Ambersweet Solar Energy Center, Indian River County 728
61. Preferred Site #61 – Treefrog Solar Energy Center, Collier County 733
62. Preferred Site #62 – Wabasso Solar Energy Center Indian River County 738
63. Preferred Site #63 – Waveland Solar Energy Center, Brevard County 743
64. Preferred Site #64 – Cardinal Solar Energy Center, Brevard County 748
65. Preferred Site #65 – Grapefruit Solar Energy Center, Hendry County 753
66. Preferred Site #66 – LaBelle Solar Energy Center, Hendry County 758
67. Preferred Site #67 – Mango Solar Energy Center, Hendry County 763
68. Preferred Site #68 – Owen Branch Solar Energy Center, Manatee County 768
69. Preferred Site #69 – Pine Lily Solar Energy Center, St. Lucie County 773
70. Preferred Site #70 – Redroot Solar Energy Center, Hendry County 778

71. Preferred Site #71 – Shell Creek Solar Energy Center, Charlotte/ DeSoto County 783
72. Preferred Site #72 – Waxweed Solar Energy Center, Hendry County 788
73. Preferred Site #73 – Wild Lime Solar Energy Center, St. Lucie County 793
74. Preferred Site #74 – Grapefruit Battery Storage Center, Hendry County 798
75. Preferred Site #75 – Mango Battery Storage Center, Hendry County 803
76. Preferred Site #76 – Owen Branch Battery Storage Center, Manatee County 808
77. Preferred Site #77 – Pine Lily Battery Storage Center, St. Lucie County 813
78. Preferred Site #78 – Redroot Battery Storage Center, Hendry County 818
79. Preferred Site #79 – Shell Creek Battery Storage Center, DeSoto/ Charlotte County 823
80. Preferred Site #80 – Waxweed Battery Storage Center, Hendry County 828
81. Preferred Site #81 – Wild Lime Battery Storage Center, St. Lucie County 833
82. Preferred Site #82 – Blanketflower Solar Energy Center, DeSoto County 838
83. Preferred Site #83 – Dove Solar Energy Center, DeSoto County 843
84. Preferred Site #84 – Ladybug Solar Energy Center, DeSoto County 848
85. Preferred Site #85 – Leafcutter Solar Energy Center, DeSoto County 853
86. Preferred Site #86 – Limpkin Solar Energy Center, DeSoto County 858
87. Preferred Site #87 – Spoonbill Solar Energy Center, Collier County 863
88. Preferred Site #88 – Caladium Solar Energy Center, Highlands County 868
89. Preferred Site #89 – New River Solar Energy Center, Union County 873
90. Preferred Site #90 – Blanketflower Battery Storage Center, DeSoto County 878
91. Preferred Site #91 – Ladybug Battery Storage Center, DeSoto County 883
92. Preferred Site #92 – Leafcutter Battery Storage Center, DeSoto County 888
93. Preferred Site #93 – Turkey Point Nuclear Units 6 & 7, Miami Dade County 893
94. Preferred Site #94 – Martin Power Plant, Martin County 898

C. Potential Sites 903
1. Potential Site #1 – Harbortown Solar Energy Center, St. Lucie County 904
2. Potential Site #2 – Horseback Solar Energy Center, St Lucie County 908
3. Potential Site #3 – Riverbreeze Solar Energy Center, St. Lucie County 912
4. Potential Site #4 – Spruce Bluff Solar Energy Center, St. Lucie County 916
5. Potential Site #5 – Cattail Solar Energy Center, Hendry County 920
6. Potential Site #6 – Flamingo Solar Energy Center, Hendry County 924
7. Potential Site #7 – Garberia Solar Energy Center, Manatee County 928
8. Potential Site #8 – Periwinkle Solar Energy Center, Hendry County 932
9. Potential Site #9 – Spider Lily Solar Energy Center, Manatee County 936
10. Potential Site #10 – Sweetbroom Solar Energy Center, Hendry County 940
11. Potential Site #11 – Carlton Solar Energy Center, St. Lucie County 944
12. Potential Site #12 – Hummingbird Solar Energy Center, Martin County 948
13. Potential Site #13 – Hurston Solar Energy Center, St. Lucie County 952
14. Potential Site #14 – Jetty Park Solar Energy Center, St. Lucie County 956
15. Potential Site #15 – Lagoon Solar Energy Center, St. Lucie County 960
16. Potential Site #16 – Lancewood Solar Energy Center, Martin County 964
17. Potential Site #17 – Lawnwood Solar Energy Center, St. Lucie County 968
18. Potential Site #18 – Maypop Solar Energy Center, Martin County 972
19. Potential Site #19 – Starboard Solar Energy Center, St. Lucie County 976
20. Potential Site #20 – Wax Myrtle Solar Energy Center, Martin County 980
21. Potential Site #21 – Edentown Solar Energy Center, Charlotte County 984
22. Potential Site #22 – Mistflower Solar Energy Center, Charlotte County 988
23. Potential Site #23 – Rosemary Solar Energy Center, Charlotte County 992
24. Potential Site #24 – Sophia Solar Energy Center, Charlotte County 996

25. Potential Site #25 – Spatterdock Solar Energy Center, Charlotte County 1,000
26. Potential Site #26 – Tippen Solar Energy Center, Charlotte County 1,004
27. Potential Site #27 – Woodpecker Solar Energy Center, Charlotte County 1,008
28. Potential Site #28 – Yellowleg Solar Energy Center, Charlotte County 1,012
29. Potential Site #29 – Cattail Battery Storage Center, Hendry County 1,016
30. Potential Site #30 – Flamingo Battery Storage Center, Hendry County 1,020
31. Potential Site #31 – Periwinkle Battery Storage Center, Hendry County 1,024
32. Potential Site #32 – Spider Lily Battery Storage Center, Manatee County 1,028
33. Potential Site #33 – Sweetbroom Battery Storage Center, Hendry County 1,032
34. Potential Site #34 – Northfork Fossil Combustion Turbine, Clay County 1,036
35. Potential Site #35 – Okeechobee Fossil Combustion Turbine, Okeechobee County 1,040
36. Potential Site #36 – Truman Fossil Combustion Turbine, Putnam County 1,044
37. Potential Site #37 – Beaty Fossil Combustion Turbine, Okeechobee County 1,048
38. Potential Site #38 – Hendry Fossil Combustion Turbine, Hendry County 1,052

List of Figures, Tables, and Maps

Figure ES-1 FPL's Fuel Mix as a Percentage of Net Electric Load 7

Figure ES-2 FPL System Heat Rate (2001-2025) 14

Table ES-1 Resource Additions/Subtractions in FPL's Resource Plan 17

Figure I.A.2.1 FPL's Generating Resources by Location (as of December 31,2025) 22

Table I.A.2.1 FPL's Generating Resources by Unit Type (as of December 31, 2025) 23

Figure I.A.2.2 FPL's Bulk Transmission System 27

Table I.A.3.1 FPL's Purchased Power Resources by Contract (as of December 31, 2025) 29

Table I.A.3.2 FPL's Firm Purchased Power Summer MW 30

Table I.A.3.3 FPL's Firm Purchased Power Winter MW 31

Figure III.A.1 Overview of IRP Process 75

Table III.E.1 List of Proposed Power Lines 96

Table III.F.1 List of FPL-Owned Solar Facilities Through April 1st, 2026 184

Table III.F.2 List of FPL Battery Storage Facilities 195

Table IV.C.1 2025 FPL Environmental Outreach Activities 407

Table IV.G.1 List of Preferred Sites 412

Table IV.G.2 List of Potential Sites 415

Figure A.A.1 Relationship of Regional Hydrogeologic Units to Major Stratigraphic Units 430

Figure A.A.2 Florida Regions Map 431

List of Schedules

Schedule 1	FPL Existing Generating Facilities as of December 31, 2025	33
Schedule 2.1	History of Energy Consumption & Number of Customers by Customer Class	58
Schedule 2.1	Forecast of Energy Consumption & Number of Customers by Customer Class	59
Schedule 2.2	History of Energy Consumption & Number of Customers by Customer Class (Continued)	60
Schedule 2.2	Forecast of Energy Consumption & Number of Customers by Customer Class (Continued)	61
Schedule 2.3	History of Energy Consumption & Number of Customers by Customer Class (Continued)	62
Schedule 2.3	Forecast of Energy Consumption & Number of Customers by Customer Class (Continued)	63
Schedule 3.1	History of Summer Peak Demand (MW)	64
Schedule 3.1	Forecast of Summer Peak Demand (MW)	65
Schedule 3.2	History of Winter Peak Demand (MW)	66
Schedule 3.2	Forecast of Winter Peak Demand (MW)	67
Schedule 3.3	History of Annual Net Energy for Load (GWh)	68
Schedule 3.3	Forecast of Annual Net Energy for Load (GWh)	69
Schedule 4	Previous Year Actual and Two-Year Forecast of Total Peak Demand And Net Energy for Load (NEL) by Month	70
Schedule 5	Actual Fuel Requirements	204
Schedule 5	Forecasted Fuel Requirements	205
Schedule 6.1	Actual Energy Sources	206
Schedule 6.1	Forecasted Energy Sources	207
Schedule 6.2	Actual Energy Sources % by Fuel Type	208
Schedule 6.2	Forecasted Energy Sources % by Fuel Type	209

Schedule 7.1 Forecast of Capacity, Demand, and Scheduled Maintenance at Time Of Summer Peak 210

Schedule 7.2 Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak 211

Schedule 8 Planned and Prospective Generating Facility Additions and Changes 212

Schedule 9 Status Report and Specifications of Proposed Generating Facilities 215

Schedule 10 Status Report and Specifications of Proposed Transmission Lines 315

Schedule 11.1 FPL Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type Actuals for the Year 2025 399

Schedule 11.2 FPL Existing Non-Firm Self-Service Renewable Generation Facilities Actuals for the Year 2025 400

Schedule 11.3 FPL Renewable Capacity and Energy Projections, 2026-2035 401

(This page is intentionally left blank.)

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten-Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's Preferred and Potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change, at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document addresses Florida Power & Light Company (FPL), which includes the service area of the former Gulf Power Company (Gulf). NextEra Energy, Inc. (NextEra Energy), the parent company of FPL, acquired Gulf in January 2019. Resource planning is now being done for the single entity of FPL, with Gulf's former service area now referred to as FPL's Northwest Florida Division (FPL NWFL). The information presented in this Site Plan is based on integrated resource planning (IRP) analyses that were carried out in 2025 and the 1st Quarter of 2026. The forecasted information presented in this plan addresses the years 2026 through 2035.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand-side management (DSM), and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

The load forecasting methodology utilized for FPL, and the resulting forecast of seasonal peaks and annual energy usage, are presented in Chapter II. Included in this discussion are the projected ongoing impacts

of federal and state energy efficiency codes and standards, the continued adoption of private solar and electric vehicles, and forecast impacts driven by expected large load additions.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses the IRP process and presents currently projected resource additions for FPL. This chapter also discusses a number of factors or issues that either have changed, or may change, the resource plan presented in this Site Plan. Furthermore, this chapter also discusses previous and planned DSM efforts, the projected significant impact of state/federal energy efficiency codes and standards, previous and planned renewable energy efforts, projected transmission additions, and the fuel cost forecasting processes.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential Site locations for additional electric generation facilities for FPL.

Site descriptions and site maps for Preferred and Potential sites are located in the Appendix.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve (12) “discussion items” which pertain to additional information that is included in a Site Plan filing.

Appendix – Site Descriptions and Site Maps for Preferred and Potential Sites.

The appendix includes all site descriptions and maps for the Preferred and Potential Sites that were included in Chapter IV.

FPL
List of Abbreviations
Used in Forms

Reference	*Abbreviation*	*Definition*
Unit Type	BS	Battery Storage
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	PV	Photovoltaic
	ST	Steam Unit (Fossil or Nuclear)
	IC	Internal Combustion
Fuel Type	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	N/A	Not Applicable
	NG	Natural Gas
	No	None
	NUC	Uranium
	Pet	Petroleum Coke
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	ULSD	Ultra - Low Sulfur Distillate
Fuel Transportation	N/A	Not Applicable
	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	L	Regulatory approval pending. Not under construction
	OP	Operating Unit
	OT	Other
	P	Planned Unit
	RT	Retired
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators
	k-Factor	The k-factor for the capital costs of a given unit is the cumulative present value of revenue requirements (CPVRR) divided by the total installed cost
	ST	Solar Together
	SoBRA	Solar Rate Base Adjustment

(This page is intentionally left blank.)

Executive Summary

This Site Plan addresses projected electric power generation resource additions and retirements for FPL for the years 2026 through 2035.

I. Background / Overview of FPL's 2026 Site Plan

This 2026 Site Plan presents the current plans to augment and enhance the electric generation capability of the FPL system to meet projected incremental resource needs for a reliable and economic electric system for 2026 through 2035. As demand for electricity continues to increase in FPL's service area and extreme weather events occur with more frequency (as reflected in recent storm activity and peak load events), it is more important than ever that FPL has sufficient resources to meet continued growth, maintain adequate reserves, and provide reliable energy at all times. In order to meet these needs economically, FPL is planning the following actions during the ten-year reporting period of this document:

1) **Install 12,293 MW of cost-effective, solar generation** – These solar additions will generate reliable energy using no fuel, which mitigates the commodity price risk to customers, enhances fuel diversity and helps secure Florida's energy independence.

2) **Install 7,454 MW of battery storage** – As a complement to FPL's planned solar additions, FPL is planning to deploy 7,454 MW of battery storage, which provides cost-effective capacity, regardless of the time of day or the weather conditions. These additions enable energy that is produced at the lowest cost to be stored and delivered when needed most. Storage acts as a key resource that improves system reliability and resource adequacy by addressing the evening peak cost-effectively.

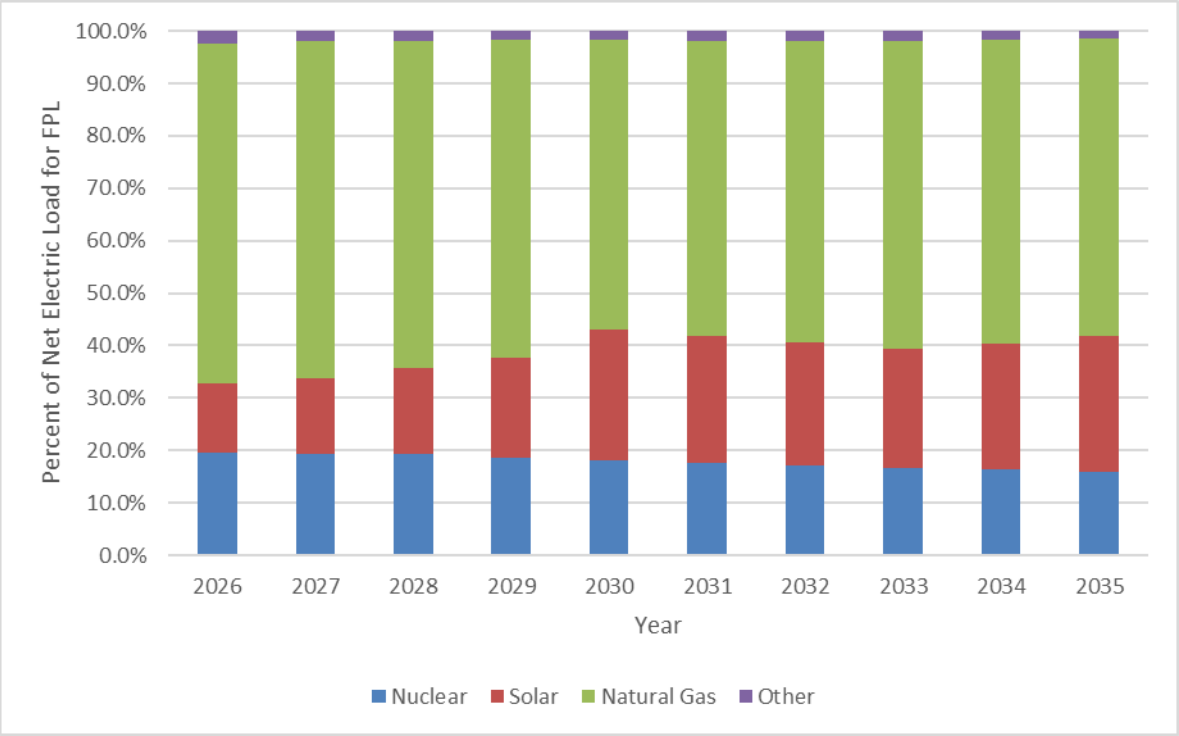
3) **Incorporate the purchase of the 672 MW Vandolah unit into FPL's generating fleet** – FPL received Federal Energy Regulatory Commission (FERC) approval for the purchase of this plant in December of 2025. Starting June 1, 2027, this plant will begin providing capacity and energy for FPL's customers.

4) **Develop natural gas capacity for in-service dates from 2032 through 2035** – Solar and battery storage remain the most cost-effective resource options, as well as the only viable options, to meet FPL's needs in the near term. However, long-term trends in load growth require FPL to continually examine other options to provide resource adequacy to its customers when they need it most. Consequently, FPL projects 3,276 MW of combustion turbine (CT) capacity coming online from 2032 through 2035.

To determine the resources needed for its system, FPL has expanded and modernized its resource adequacy planning to reflect the evolving characteristics of its system and the conditions under which reliability risks can occur. Historically, FPL relied on traditional deterministic and probabilistic reliability criteria focused on peak period conditions. As FPL's generation and load portfolio has evolved, these peak-based metrics alone are no longer sufficient to identify periods of greatest reliability risk. Accordingly, FPL enhanced its planning framework by applying a comprehensive, stochastic loss of load probability (LOLP) analysis in 2025 that evaluates system reliability across every hour of the year. This approach captures variability in customer demand, generating unit availability, and solar performance, identifies hours when reserves are most constrained—including periods of peak net demand—and informs the selection of resources capable of addressing those needs. FPL's proposed resource additions through 2029 reflect the results of this enhanced analysis, and projected additions in the 2030 through 2035 timeframe will continue to be evaluated using these comprehensive methods to ensure resource adequacy for customers under a wide range of system conditions.

Regarding FPL's fuel mix, FPL delivered approximately 20% of its energy from nuclear generation and 11% from solar generation during 2025. Nearly all the remainder of FPL's energy generation in 2025 came from natural gas. By 2035, the last year of the ten-year reporting period addressed in this document, the percentage of the total energy delivered to all customers on FPL's system is projected to be approximately 16% from nuclear and 26% from solar generation. New cost-effective solar will provide fuel diversity and energy independence by reducing the amount of natural gas FPL will use to generate electricity and adding battery storage will provide cost-effective capacity to help maintain system resource adequacy. This diversity will also help to act as a hedge against swings in natural gas price volatility, providing additional savings to FPL customers during these periods. The graph below in Figure ES-1 represents a ten-year projection for the years 2026 through 2035 of the percentage of FPL's total generation (GWh) by fuel type. Further details regarding projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 in Chapter III.

Figure ES-1: FPL's Fuel Mix as a Percentage of Net Electric Load



By design, the primary focus of this document is on projected supply-side additions, *i.e.*, electric generation capability and the sites for these additions. The supply-side additions discussed herein are resources projected to be needed after accounting for existing and projected demand-side management (DSM) resources (including demand response and energy efficiency). In April of 2024, FPL filed its DSM Goals for the period of 2026 through 2035, and these Goals were approved by the FPSC on December 3, 2024. FPL's DSM Plan to meet these goals was filed and approved in 2025. The approved DSM Plan addresses demand-side activities that reduce system peak loads and annual energy usage, along with consideration of the impacts of DSM on electric rates under which all customers are served. FPL's DSM programs are discussed in more detail in Chapters I, II, and III.

In addition to the impacts of these utility DSM programs, FPL's load forecast accounts for a broad range of customer behavior and technology adoption trends that shape future electricity demand. This includes energy efficiency that results directly from federal and state energy efficiency codes and standards, the continued installation of private rooftop photovoltaic (PV) solar systems by customers, and the continued adoption of electric vehicles (EVs) being charged on the grid. Together, these factors represent significant load-shaping influences that are incorporated into FPL's planning process. The projected impacts of

energy efficiency codes and standards, rooftop PV, and EV adoption are discussed in further detail in Chapter II.

FPL's projected resource additions and retirements over the ten-year reporting period are summarized below in Section II of this Executive Summary. In addition, there are several factors influencing ongoing resource planning efforts. These factors could result in different resources being added in the future than those presented in this document. These factors are discussed in Section III of this Executive Summary. Additional information regarding these topics is presented later in this document in Chapter III.

II. Summary of Projected Changes in Resources:

A summary of the projected resources, including additions and retirements, is presented below. This discussion is presented in terms of the various types of resource options (such as solar and battery storage) in the resource plan.

Solar:

At the end of 2025, FPL had a total of approximately 7,932 MW[1] of utility-owned solar generation, all of which are photovoltaic (PV) facilities. These solar sites are located throughout FPL's service area.

The resource plan presented in this Site Plan continues to show significant increases in solar resources over the ten-year reporting period. Approximately 12,293 MW of additional, cost-effective solar generation is projected to be added in the 2026 through 2035 time period. These solar MW consist of solar facilities that are projected to be 74.5 MW each. When combining these projected additional solar facilities with the approximate 7,932 MW of solar already installed on FPL's system at the end of 2025, FPL's projected total of solar capacity by the end of 2035 is 20,225 MW.

FPL received cost recovery approval for the 2026 solar additions in this year's resource plan in its settlement agreement in the 2025 rate case filing. FPL's solar additions of 1,192 MW in 2027, 1,490 MW in 2028, and 1,788 MW in 2029 are eligible for cost recovery through the Solar and Battery Base Rate Adjustment (SoBRA) mechanism outlined in the 2025 Settlement Agreement. FPL's resource plan also includes an additional 298 MW in 2028, 596 MW in 2029, and 745 MW in 2030 that are projected to be cost-effective resource additions. The other solar additions shown in this Site Plan in the years 2034 and 2035 are also projected to be cost-effective. FPL's resource planning work in 2026 and beyond will continue to analyze the projected system economics of these later solar additions. FPL will seek Florida

[1] Each reference to solar capacity throughout this Site Plan reflects the nameplate rating, Alternating Current (AC), unless noted otherwise. All future solar generation is assumed to be PV facilities.

Public Service Commission (FPSC) approval for cost recovery of these later solar additions at appropriate times as has been FPL's practice with previous solar additions.

Battery Storage:

Currently, FPL has 991 MW of large-scale, grid-connected battery storage installed on its system. 409 MW of battery storage was placed in-service at the existing Manatee plant site, while two 30 MW battery storage facilities were installed at the Echo River and Sunshine Gateway solar centers in the FPL service area. All of these battery storage facilities were placed into service at the end of 2021 and are charged by existing solar facilities. In the 4th Quarter of 2025, FPL placed a combined 521.5 MW of new battery storage into service. This battery storage is made up of seven 74.5 MW batteries that are co-located at existing solar sites throughout FPL's Northwest Florida (NWFL) service area. The addition of these battery storage facilities both improves overall system reliability (especially in areas of the NWFL service area identified to have the largest need) and increases operational versatility by allowing the batteries to be charged by solar energy, the lowest cost resource available, generated at adjacent solar sites. More information on these sites can be found in the Tables and Schedules in Chapter I.

FPL's battery storage additions in 2026 through 2029 totaling 3,431 MW are consistent with FPL's approved settlement agreement for base rates through 2029. The battery additions in 2028 and 2029 are also eligible for cost recovery through the SoBRA mechanism outlined in the 2025 Settlement Agreement. For the 2030 through 2035 time period, FPL plans to add 4,023 MW of battery storage. In total, FPL's resource plan presented in this Site Plan projects that an additional 7,454 MW (nameplate) of battery storage facilities will be installed by 2035, which results in a total of 8,445 MW by the end of 2035. These battery storage facilities will primarily be sited adjacent to solar facilities throughout FPL's service area. Like the 521.5 MW of battery storage sited in NWFL, these additions are projected to both improve overall system reliability and increase operational versatility by allowing batteries to be charged by the lowest cost resource available.

In addition to the large-scale batteries that FPL factors into its resource planning analyses, FPL's system also includes several smaller-scale batteries that provide varied services to FPL's system. These batteries are discussed further in Chapter III.

Development of New Combustion Turbine Generation:

In the near term, solar and battery storage continue to be the most cost-effective and only available resource options for FPL customers. However, long-term trends of load growth require FPL to examine

other options to provide resource adequacy to its customers when they need it the most. Consequently, FPL projects 3,276 MW of new CT capacity coming online in 2032 through 2035.

Modernization of FPL's Existing Fossil-Fueled Generation:

For several years, FPL has undertaken a variety of measures to modernize its fossil-fueled generation fleet based on cost-effectiveness. These efforts have resulted in substantial enhancements to the fleet of generating units, including improved system fuel efficiency and increased capacity, reduced system air emission rates, and dramatically reduced fuel-related costs for FPL customers. FPL plans to continue these efforts and to further improve the efficiency and capabilities of FPL's generation fleet through two principal initiatives: (i) retirement of existing generating units that are no longer economic to operate, and (ii) enhancements to existing generating units. These modernization efforts are separately described below.

(i) Retirement of Existing Generating Units That Are No Longer Economic to Operate:

The resource plan for the 2026 TYSP reflects the retirement of two units: Gulf Clean Energy Center Units 4 & 5. These units will be retired at the end of 2029.

(ii) Enhancements to Existing Generating Units:

In previous Site Plans, FPL discussed plans to upgrade the CT components in a number of FPL's existing combined cycle units to continue to add additional summer capacity and improve the overall fuel efficiency of the fleet. These upgrade efforts remain a part of FPL's resource planning in this Site Plan. Information regarding the specific units, timing, and magnitude of these upgrades is presented in Schedule 8 in Chapter III.

Nuclear Energy:

Nuclear energy remains an important factor in FPL's resource planning due to its combination of low fuel cost, around-the-clock operation, and location close to major load centers. FPL's current nuclear fleet consists of four nuclear units located at two sites within its service area. In total, these sites provide approximately 3,500 MW of summer capacity and, in 2025, provided 29,483 GWh of energy to FPL's system. This amount of energy represented roughly 20% of FPL's generation in 2025. In order for these units to continue to provide around-the-clock energy to FPL's customers, FPL secured Subsequent License Renewals (SLR) for both units at Turkey Point and is in the process of securing SLRs for both units at St. Lucie. More detailed information on these re-licensing efforts is available in Chapter III. For purposes of this Site Plan, FPL's resource planning analyses have assumed the continued operation of

Turkey Point Units 3 & 4 through 2052 and 2053, respectively, and St. Lucie Units 1 & 2 through 2056 and 2063, respectively.

Regarding potential future nuclear additions, in June 2009, FPL began the process of securing Combined Operating Licenses (COL) from the federal Nuclear Regulatory Commission (NRC) for two future nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (the location of two existing nuclear generating units). In April 2018, FPL received NRC approval for these two COLs, and these licenses currently remain valid with the earliest possible in-service dates for Turkey Point 6 & 7 beyond the ten-year period addressed in this 2026 Site Plan. FPL is also continuing to monitor advanced nuclear power options such as small modular reactors (SMR). To prepare for the potential future commercial viability of SMRs, FPL plans to begin the initial stages of Early Site Permitting, available under NRC rules, in the 2026-2027 timeframe for a potential SMR at a site adjacent to an existing nuclear power plant. This strategic move is aimed at minimizing risks, allowing emerging technologies to mature, and enabling robust and well-developed regulatory frameworks prior to deployment, while remaining cognizant of the current high costs of nuclear and SMR development and taking a stepwise approach. FPL is closely monitoring current initiatives at both the U.S. Department of Energy and the NRC. By taking these steps early on, FPL aims to be well-positioned to benefit from future nuclear deployment. The projected in-service date of an SMR would be outside the ten-year period addressed in this Site Plan.

III. Other Factors Influencing FPL's Resource Planning Work:

There are a number of factors that have influenced, or which may influence, FPL's resource planning work. Eleven total factors are summarized below. These additional factors are presented in no particular order, and their potential influences on FPL's resource planning work are further discussed in Chapters II and III.

Factor # 1: Impacts of Tax Credits for Batteries and Solar. FPL's resource planning work continues to factor in tax credits for new utility-owned batteries and solar, as well as recent changes in the long-term deployment of these credits. For new utility-owned standalone batteries, the 30% Investment Tax Credit (ITC) effectively lowers the capital cost for a new battery, with the potential of an additional 10% if the battery is located in a specific area. For new utility-owned solar, a utility can elect a Production Tax Credit (PTC) for new solar that is based on the amount of energy (MWh) the new solar facility generates each year for the first ten years of operation. For future resource additions, the PTC rate in 2026 starts at $31

for each MWh generated.[2] The $31 per MWh credit amount for a new solar facility that comes in-service increases with inflation each year. In mid-2025, the One, Big, Beautiful Bill Act (OBBBA) was signed and changed the projection of future ITCs and PTCs. With this new bill enacted, all of FPL's projected solar additions through 2026 will qualify for 100% of the PTC. FPL's projected solar additions through 2030 will also still be eligible for the full PTC, as all of those sites come within the "Safe Harbor" guidelines that require construction to commence on or before one year of the enactment of the OBBBA. The additional solar units that are presented in this Site Plan through the remainder of the ten-year period will not be eligible for the PTC. The battery storage ITC has also been affected by the OBBBA, but the associated impacts occur on a different timeline. In terms of the resource additions in this Site Plan, all planned battery storage will still be eligible for the 30% ITC through 2035. FPL's resource plan presented in this Site Plan accounts for the effects of these tax credits and the impact of the OBBBA.

Factor # 2: The critical need to maintain a balance between load and generating capacity in specific regions of FPL's service area, such as in NWFL and Southeastern Florida (Miami-Dade and Broward Counties). This balance has both reliability and economic implications for FPL's system and customers, and it is a key reason that FPL has expanded generation and transmission in specific areas in the past.

Factor # 3: The desire to maintain/enhance fuel diversity in the FPL system while considering system economics and reliability. Diversity is sought in terms of the types of fuel that FPL utilizes and how these fuels are transported to the locations of FPL's generation units. The objective of fuel diversity is considered in light of economic impacts to FPL customers. For example, FPL is projecting the addition of significant amounts of cost-effective PV generation throughout the ten-year reporting period of this Site Plan. These PV additions enhance fuel diversity while at the same time allowing for the lowest cost generation resource to be constructed and operated. To enhance the reliability of these PV solar additions, FPL is planning to add cost-effective battery storage to maintain adequate generation and reserves at the time of the net system peak (FPL's peak after accounting for solar generation). At the same time, FPL is continuing to retire generating units that are no longer cost-effective for FPL customers. In addition, FPL also seeks to further enhance the efficiency with which it uses natural gas to generate electricity and maintain the ability to use backup distillate oil that is stored on-site at many of FPL's gas-fueled generating units for purposes of system reliability. All of the aforementioned additions enhance the overall fuel diversity of FPL's system, which increases the energy independence of FPL's customers in the State of Florida.

[2] To illustrate the magnitude of the impact of the solar PTC, take a simple example of a 74.5 MW solar facility that produces approximately 150,000 MWh per year in 2026 (*i.e.*, assuming a net capacity factor of 23%). The proposed solar PTC for that year would result in a tax credit of (150,000 MWh x $31/MWh =) $4.7 million. This first year tax credit would then be extended for nine more years while being adjusted for inflation.

Factor # 4: The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations. FPL addresses this factor through the use of a 10% generation-only reserve margin (GRM) reliability criterion to complement its other two reliability criteria: a 20%[3] total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year LOLP criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability and operations in a comprehensive manner.

Factor # 5: The significant impact of federal and state energy efficiency codes and standards. The incremental impacts of these energy efficiency codes and standards are projected to have significant impacts by reducing forecasted summer and winter peak loads, and by reducing annual net energy for load (NEL), in FPL's system. From the end of 2025 through 2035, these energy efficiency codes and standards are projected to reduce summer peak load by approximately 1,900 MW, reduce winter peak load by approximately 420 MW, and reduce annual energy usage by approximately 2,800 GWh. In addition, energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs. The projected impacts of these energy efficiency codes and standards are discussed in more detail in Chapter II.

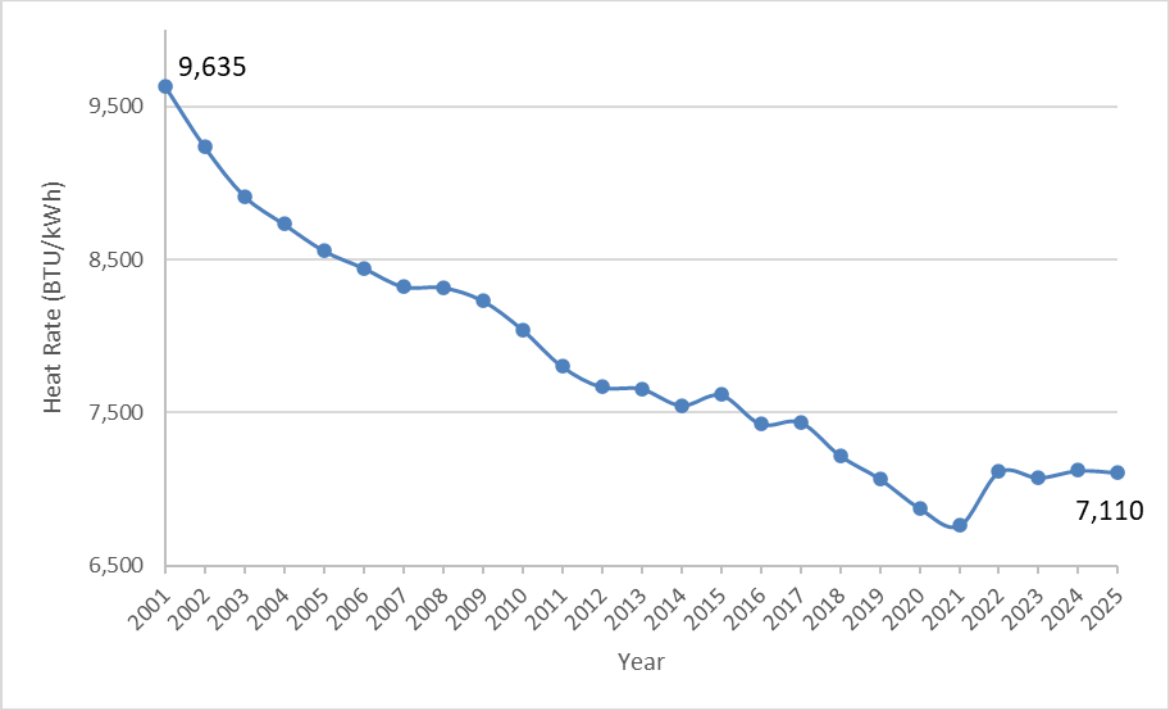
Factor # 6: The fuel cost and efficiency of FPL's fossil-fueled generation fleet and the avoidance of fuel costs through increased solar generation. There are two main factors that drive utility system costs for FPL's fossil-fueled generation fleet: (i) forecasted natural gas costs, and (ii) the efficiency with which generating units convert fuel into electricity. While natural gas costs always remain subject to supply, demand and geopolitical impacts, forecasted natural gas costs have recently been one of the lowest cost options for fuel, leading to low overall system fuel costs for FPL's customers when compared with fuels such as oil and coal. In addition to these low natural gas costs, FPL customers also experience lower rates resulting from two other characteristics of FPL's system: 1) the amount of solar generation on FPL's system and 2) the efficiency of FPL's fossil-fueled generating units.

In 2025, FPL customers saved approximately $404 million in system fuel costs from FPL having solar generation on its system. Since 2017 (when FPL began scaling investment in cost-effective large-scale solar facilities), FPL has avoided approximately $1.5 billion of fuel costs because of its solar generation.

[3] The 20% reserve margin requirement is a minimum requirement – FPL's projected reserve margin may be higher than 20% during some years as additional resources are added for resource needs and meeting other reliability criteria.

FPL has built a generating fleet that is increasingly fuel efficient. The amount of natural gas (measured in British Thermal Units, or BTU) needed to produce a kilowatt-hour (kWh) of electricity has declined from approximately 9,635 in 2001 to approximately 7,110 in 2025, as shown in Figure ES-2 below. This improvement of approximately 26% in fuel efficiency is truly significant, especially when considering the 20,000 MW-plus magnitude of gas-fueled generation on FPL's system. This long-term trend of increasing system efficiency benefits customers, as it helps to lower customers' electric rates.

Figure ES-2: FPL System Heat Rate (2001-2025)



This significant improvement in FPL's fuel efficiency has resulted in FPL customers saving $860 million in fuel costs in 2025, and an estimated cumulative savings for FPL customers of approximately $16.1 billion from 2001 through 2025.

Factor # 7: Projected CO_2 regulation and associated compliance costs. Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has utilized projected compliance costs for CO_2 emissions prepared by an independent consultant, ICF, in its resource planning work. FPL continues to utilize ICF's forecast of projected CO_2 compliance costs in its resource planning process. The projected compliance costs in the current plan are the same as those used in the 2025 TYSP.

Factor # 8: Projected increases in electric vehicle (EV) adoption. FPL's current load forecast continues to project increasing levels of EV adoption throughout the ten-year period. The overall forecast of EV penetration is lower when compared to the 2025 TYSP but still impacts FPL's overall projections of demand and energy. These projected impacts of EVs on annual energy usage and peak loads are discussed later in this document in Chapter II.

Factor # 9: Enhancing system reliability to prepare for extreme weather events. Over the past several years, extreme weather events have caused significant outages and disruptions to electric grids across the country. These events include widespread hot weather in California in the summer of 2020, historic cold weather in Texas in February 2021, and extreme cold conditions throughout the Mid-Atlantic and Southeast around Christmas of 2022. FPL's NWFL area has continually set records in winter peak demand, including a record peak early in 2025 when widespread snowfall occurred throughout northern Florida. FPL's overall system has also hit all-time peaks for summer in 2025 and winter in early 2026. In addition to these peak events, FPL's service area regularly experiences periods of hotter than average weather throughout the year and hurricanes that can potentially affect the output of its generation fleet. While FPL does not plan its system around extreme events, it is prudent to consider and prepare for the possibility of extreme weather events and the ability to reliably serve customers under those circumstances. To that end, FPL has reviewed the lessons learned from the outages and service disruptions experienced in other jurisdictions and enhanced its own system so that it is adequately prepared. This includes winterizing FPL's nuclear and fossil-fueled generation units, enhancing cooperation and preparation between FPL and suppliers of natural gas and fuel oil, and keeping generation units as "extreme winter only" units that will provide the lowest cost backup capacity in the event of extreme winter weather in FPL's service area. The additional dispatchable resources that FPL is adding throughout the ten-year period will also support reliability and grid stability throughout the year, including during extreme weather events.

FPL will continue to work with regulatory authorities, such as the FERC, the FPSC, and the North American Electric Reliability Corporation (NERC), to follow their guidance regarding proper planning procedures for extreme weather events.

Factor # 10: Enhancing the system for resource adequacy and system reliability throughout the entire year. FPL's planning processes center around maintaining the reliability of its bulk electric system. For the past two decades, the metric that drove most of FPL's resource needs was its minimum 20% standard reserve margin, calculated at the time of summer and winter peak load. However, FPL's evolving system requires more in-depth reliability metrics to fully analyze resource adequacy across every hour of the year and through various potential scenarios, including variations in load, generating outages, and solar

performance. Therefore, FPL has expanded use of its LOLP metric to include stochastic modeling that fully encompasses all of these scenarios, leading to a more robust evaluation of the reliability and resource adequacy of FPL's system. FPL's planned resources in this Site Plan address resource adequacy concerns by adding a variety of resources throughout the ten-year period that results in a robust, reliable, and cost-effective system to serve FPL's customers. This expanded methodology is discussed more thoroughly in Chapter III.

Factor # 11: Future impacts of large load customers.

Over the past several years, large load customers with high load factors have grown extensively throughout the U.S. These customers have expressed interest in establishing operations within Florida, which would greatly impact the demand and energy in FPL's future forecast. FPL's current load projections assume that demand from large load customers will materialize starting in 2028 and reach a peak demand of 3 GW by 2035. FPL's projections of demand and energy (and the associated resources needed to meet this demand) factor in this increase in load. FPL will continually examine the projected impacts of this demand on its future resource needs.

Each of these factors described above will continue to be examined in FPL's ongoing resource planning processes in 2026 and future years.

IV. FPL's Projected Resource Plan:

FPL's projected resource plan for the 2026 Site Plan is shown below. Regarding the resources projected in the Site Plan, final decisions have not been made regarding many of the resource additions shown, nor are such decisions needed at this time. This is particularly so for the resource additions shown for years 2030 through 2035, which are further out in the planning horizon. Consequently, resource additions shown for these later years have an increased likelihood for change in future planning.

Table ES-1: Resource Additions/Subtractions in FPL's Resource Plan

Year	Changes to Existing Generation	Subtractions	New Generation Additions	Summer RM%
2026			894 MW Solar 1,419.5 MW Battery	24.1
2027	+43 MW CC Upgrades	Broward South (4 MW)	1,192 MW Solar 819.5 MW Battery 672 MW Vandolah CTs	30.8
2028	+19 MW CC Upgrades	Lansing Smith 3A (32 MW)	1,788 MW Solar 596 MW Battery	29.0
2029		GCEC 4 (75 MW), GCEC 5 (75 MW)	2,384 MW Solar 596 MW Battery	27.7
2030		Perdido 1&2 (3 MW)	2,980 MW Solar 596 MW Battery	26.2
2031		Pea Ridge (12 MW)	1,192 MW Battery	24.8
2032		Palm Beach SWA 1 (40 MW)	4x0 CT (936 MW) 596 MW Battery	24.7
2033			4x0 CT (936 MW) 596 MW Battery	24.8
2034			4x0 CT (936 MW) 1,490 MW Solar 223.5 MW Battery	24.9
2035			2x0 CT (468 MW) 1,564.5 MW Solar 819.5 MW Battery	24.7
		Nameplate MW Solar Additions (2026-2035):	**12,293**	
		Nameplate MW Storage Additions (2026-2035):	**7,454**	
		Fossil MW Additions* (2026-2035):	**3,948**	

All solar and battery storage additions are in nameplate MW.
*Includes the acquisition of the Vandolah unit.

(This page is intentionally left blank.)

CHAPTER I

Description of Existing Resources

(This page is intentionally left blank.)

I.A FPL System:

I.A.1 Description of Existing Resources

FPL's service area (including the former Gulf Power area now referred to as FPL NWFL) contains approximately 35,000 square miles. Currently, FPL serves more than 6 million customer accounts representing approximately 12 million people in 43 counties in peninsular and Northwest Florida. These customers are served by a variety of resources including: FPL-owned fossil-fuel, renewable (solar), and nuclear generating units; non-utility owned generation; DSM; and purchased power.

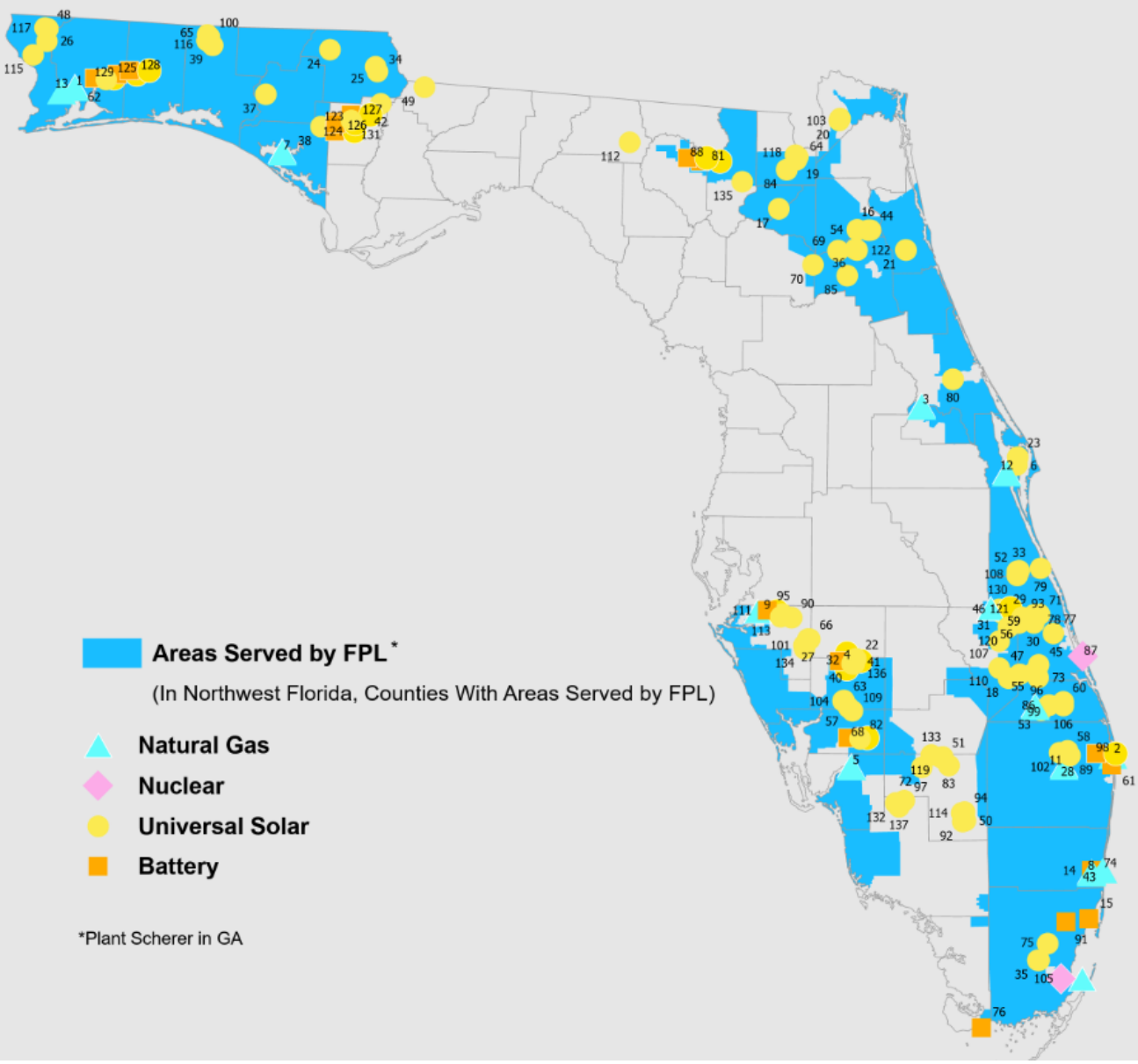
I.A.2 FPL - Owned Resources

As of December 31, 2025, FPL owned electric generating resources located at 116 sites distributed geographically throughout its service area and one site in Georgia (partial FPL ownership of one unit). These generating facilities consist of: four nuclear units, one coal steam-unit (the aforementioned partially owned unit in Georgia), 17 combined-cycle (CC) units, six fossil steam units, four gas turbines (GTs), 17 simple-cycle combustion turbines (CTs), two landfill gas units, ten battery storage units, and 108 solar PV facilities. The locations of the 169 generating units that were in commercial operation on December 31, 2025, are shown on Figure I.A.2.1 and in Table I.A.2.1.

FPL's bulk transmission system, including both overhead and underground lines, is comprised of approximately 9,700 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through FPL's 932 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.2.

FPL Generating Resources by Location



There are four small battery pilot projects shown on the map that are not listed in Table I.A.2: #26 – Florida Bay, #32 – Southwest, #36 – Wynwood, and #57 – FIU Microgrid. These sites are discussed in Chapter III.

Figure I.A.2.1: FPL's Generating Resources by Location (as of December 31, 2025)

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2025)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	Nuclear				
87	St. Lucie [2/]	St. Lucie County, FL	2	Nuclear	1,821
10	Turkey Point	Miami-Dade County, FL	2	Nuclear	1,681
	Total Nuclear:		**4**		**3,502**
	Coal Steam				
-	Scherer*	Monroe County, Ga	1	Coal	215
	Total Coal Steam:		**1**		**215**
	Combined-Cycle				
5	Fort Myers	Lee County, FL	1	Gas	1,822
111	Manatee	Manatee County, FL	1	Gas	1,246
3	Sanford	Volusia County, FL	2	Gas	2,418
7	Lansing Smith*	Bay County, FL	1	Gas	641
12	Cape Canaveral	Brevard County, FL	1	Gas/Oil	1,290
99	Martin	Martin County, FL	3	Gas/Oil	2,223
67	Okeechobee [3/]	Okeechobee County, FL	1	Gas/Oil	1,720
74	Port Everglades	City of Hollywood, FL	1	Gas/Oil	1,237
2	Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,290
10	Turkey Point	Miami-Dade County, FL	1	Gas/Oil	1,300
11	West County	Palm Beach County, FL	3	Gas/Oil	3,771
14	Dania Beach Clean Energy Center	Broward County, FL	1	Gas/Oil	1,246
	Total Combined Cycle:		**17**		**20,204**
	Gas/Oil Steam				
9	Manatee [4/]	Manatee County, FL	2	Gas/Oil	0
13	Gulf Clean Energy Center*	Escambia County, FL	4	Gas Steam	952
	Total Oil/Gas Steam:		**6**		**952**
	Gas Turbines(GT)				
5	Fort Myers (GT)	Lee County, FL	2	Oil	102
8	Lauderdale (GT)	Broward County, FL	2	Gas/Oil	69
	Total Gas Turbines/Diesels:		**4**		**171**
	Combustion Turbines				
8	Lauderdale	Broward County, FL	5	Gas/Oil	1,155
5	Fort Myers	Lee County, FL	4	Gas/Oil	852
1	Pea Ridge*	Santa Rosa County, FL	3	Gas	12
7	Lansing Smith*	Bay County, FL	1	Oil	32
13	Gulf Clean Energy Center*	Escambia County, FL	4	Gas	926
	Total Combustion Turbines:		**17**		**2,977**
	Land Fill Gas				
69	Perdido LFG*	Escambia County, FL	2	LFG	3
	Total LFG:		**2**		**3**

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

2/ Total capability of St. Lucie 1 is 981 Summer /1,003 Winter MW. FPL's share of St. Lucie 2 is 840 Summer /860 Winter MW.
FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

3/ As part of the Okeechobee Hydrogen Gas Pilot Program, a portion of the CO_2 generated from the unit is transferred to an electrolyzer where it is then converted into Hydrogen Gas.

4/ Manatee Units 1 & 2 are Winter Peaking ONLY units. They will only be manned and operated during an Extreme Winter event in which additional capacity is needed to meet load.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2025)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	Battery Storage				
9	Manatee Battery Storage	Manatee County, FL	1	Storage	409
81	Sunshine Gateway Battery Storage	Columbia County, FL	1	Storage	30
88	Echo River Battery Storage	Suwannee County, FL	1	Storage	30
62	Big Juniper Battery Storage	Santa Rosa County, FL	1	Storage	74.5
128	Kayak Battery Storage	Okaloosa County, FL	1	Storage	74.5
125	Canoe Battery Storage	Okaloosa County, FL	1	Storage	74.5
123	Chipola Battery Storage	Calhoun County, FL	1	Storage	74.5
126	Fourmile Creek Battery Storage	Calhoun County, FL	1	Storage	74.5
124	Shirer Branch Battery Storage	Calhoun County, FL	1	Storage	74.5
127	Tenmile Creek Battery Storage	Calhoun County, FL	1	Storage	74.5
	Total Battery Storage:		**10**		**991**
	PV				
4	DeSoto Solar	DeSoto County, FL	1	Solar Energy	25
68	Babcock Ranch Solar	Charlotte County, FL	1	Solar Energy	74.5
40	Citrus Solar	DeSoto County, FL	1	Solar Energy	74.5
9	Manatee Solar	Manatee County, FL	1	Solar Energy	74.5
6	Space Coast Solar	Brevard County, FL	1	Solar Energy	10
77	Interstate Solar	St. Lucie County, FL	1	Solar Energy	74.5
75	Miami Dade Solar	Miami-Dade County, FL	1	Solar Energy	74.5
80	Pioneer Trail Solar	Volusia County, FL	1	Solar Energy	74.5
81	Sunshine Gateway Solar	Columbia County, FL	1	Solar Energy	74.5
70	Horizon Solar	Alachua County, FL	1	Solar Energy	74.5
41	Wildflower Solar	DeSoto County, FL	1	Solar Energy	74.5
78	Indian River Solar	Indian River County, FL	1	Solar Energy	74.5
69	Coral Farms Solar	Putnam County, FL	1	Solar Energy	74.5
72	Hammock Solar	Hendry County, FL	1	Solar Energy	74.5
79	Barefoot Bay Solar	Brevard County, FL	1	Solar Energy	74.5
71	Blue Cypress Solar	Indian River County, FL	1	Solar Energy	74.5
73	Loggerhead Solar	St. Lucie County, FL	1	Solar Energy	74.5
82	Babcock Preserve Solar	Charlotte County, FL	1	Solar Energy	74.5
83	Blue Heron Solar	Hendry County, FL	1	Solar Energy	74.5
22	Cattle Ranch Solar	DeSoto County, FL	1	Solar Energy	74.5
88	Echo River Solar	Suwannee County, FL	1	Solar Energy	74.5
19	Egret Solar	Baker County, FL	1	Solar Energy	74.5
89	Hibiscus Solar	Palm Beach County, FL	1	Solar Energy	74.5
18	Lakeside Solar	Okeechobee County, FL	1	Solar Energy	74.5
20	Nassau Solar	Nassau County, FL	1	Solar Energy	74.5
84	Northern Preserve Solar	Baker County, FL	1	Solar Energy	74.5
55	Okeechobee Solar	Okeechobee County, FL	1	Solar Energy	74.5
90	Southfork Solar	Manatee County, FL	1	Solar Energy	74.5
86	Sweetbay Solar	Martin County, FL	1	Solar Energy	74.5
21	Trailside Solar	St. Johns County, FL	1	Solar Energy	74.5
85	Twin Lakes Solar	Putnam County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2025)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	PV Continued				
17	Union Springs Solar	Union County, FL	1	Solar Energy	74.5
16	Magnolia Springs Solar	Clay County, FL	1	Solar Energy	74.5
30	Pelican Solar	St. Lucie County, FL	1	Solar Energy	74.5
33	Palm Bay Solar	Brevard County, FL	1	Solar Energy	74.5
32	Rodeo Solar	DeSoto County, FL	1	Solar Energy	74.5
23	Discovery Solar	Brevard County, FL	1	Solar Energy	74.5
29	Orange Blossom Solar	Indian River County, FL	1	Solar Energy	74.5
28	Sabal Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
31	Fort Drum Solar	Okeechobee County, FL	1	Solar Energy	74.5
27	Willow Solar	Manatee County, FL	1	Solar Energy	74.5
94	Ghost Orchid Solar	Hendry County, FL	1	Solar Energy	74.5
92	Sawgrass Solar	Hendry County, FL	1	Solar Energy	74.5
96	Sundew Solar	St. Lucie County, FL	1	Solar Energy	74.5
97	Immokalee Solar	Collier County, FL	1	Solar Energy	74.5
93	Grove Solar	Indian River County, FL	1	Solar Energy	74.5
95	Elder Branch Solar	Manatee County, FL	1	Solar Energy	74.5
24	Blue Indigo Solar*	Jackson County, FL	1	Solar Energy	74.5
25	Blue Springs Solar*	Jackson County, FL	1	Solar Energy	74.5
26	Cotton Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
44	Anhinga Solar	Clay County, FL	1	Solar Energy	74.5
34	Apalachee Solar*	Jackson County, FL	1	Solar Energy	74.5
129	Blackwater Solar*	Santa Rosa County, FL	1	Solar Energy	74.5
47	Bluefield Preserve Solar	St. Lucie County, FL	1	Solar Energy	74.5
46	Cavendish Solar	Okeechobee County, FL	1	Solar Energy	74.5
39	Chautauqua Solar*	Walton County, FL	1	Solar Energy	74.5
123	Chipola Solar*	Calhoun County, FL	1	Solar Energy	74.5
37	Cypress Pond Solar*	Washington County, FL	1	Solar Energy	74.5
36	Etonia Creek Solar	Putnam County, FL	1	Solar Energy	74.5
35	Everglades Solar	Miami-Dade County, FL	1	Solar Energy	74.5
48	First City Solar*	Escambia County, FL	1	Solar Energy	74.5
42	Flowers Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
45	Pink Trail Solar	St. Lucie County, FL	1	Solar Energy	74.5
38	Saw Palmetto Solar*	Bay County, FL	1	Solar Energy	74.5
124	Shirer Branch Solar*	Calhoun County, FL	1	Solar Energy	74.5
49	Wild Azalea Solar*	Gadsden County, FL	1	Solar Energy	74.5
50	Beautyberry Solar	Hendry County, FL	1	Solar Energy	74.5
51	Caloosahatchee Solar	Hendry County, FL	1	Solar Energy	74.5
125	Canoe Solar*	Okaloosa County, FL	1	Solar Energy	74.5
52	Ibis Solar	Brevard County, FL	1	Solar Energy	74.5
53	Monarch Solar	Martin County, FL	1	Solar Energy	74.5
59	Orchard Solar	Indian River/St. Lucie County, FL	1	Solar Energy	74.5
55	Pineapple Solar	St. Lucie County, FL	1	Solar Energy	74.5
57	Prairie Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
58	Silver Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2025)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	PV Continued				
54	Terrill Creek Solar	Clay County, FL	1	Solar Energy	74.5
56	Turnpike Solar	Indian River County, FL	1	Solar Energy	74.5
95	White Tail Solar	Martin County, FL	1	Solar Energy	74.5
62	Big Juniper Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
126	Fourmile Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
63	Hawthorne Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
64	Nature Trail Solar	Baker County, FL	1	Solar Energy	74.5
65	Pecan Tree Solar*	Walton County, FL	1	Solar Energy	74.5
66	Sambucus Solar	Manatee County, FL	1	Solar Energy	74.5
115	Sparkleberry Solar*	Escambia County, FL	1	Solar Energy	74.5
113	Three Creeks Solar	Manatee County, FL	1	Solar Energy	74.5
116	Wild Quail Solar*	Walton County, FL	1	Solar Energy	74.5
114	Woodyard Solar	Hendry County, FL	1	Solar Energy	74.5
121	Buttonwood Solar	St. Lucie County, FL	1	Solar Energy	74.5
118	Cedar Trail Solar	Baker County, FL	1	Solar Energy	74.5
122	Georges Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
119	Hendry Isles Solar	Hendry County, FL	1	Solar Energy	74.5
120	Honeybell Solar	Okeechobee County, FL	1	Solar Energy	74.5
117	Mitchell Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
128	Kayak Solar*	Okaloosa County, FL	1	Solar Energy	74.5
112	Norton Creek Solar	Madison County, FL	1	Solar Energy	74.5
102	Holowpaw Solar	Palm Beach County, FL	1	Solar Energy	74.5
110	Speckled Perch Solar	Okeechobee County, FL	1	Solar Energy	74.5
107	Big Water Solar	Okeechobee County, FL	1	Solar Energy	74.5
106	Fawn Solar	Martin County, FL	1	Solar Energy	74.5
104	Hog Bay Solar	DeSoto County, FL	1	Solar Energy	74.5
109	Green Pasture Solar	Charlotte County, FL	1	Solar Energy	74.5
103	Thomas Creek Solar	Nassau County, FL	1	Solar Energy	74.5
105	Redlands Solar	Miami-Dade County, FL	1	Solar Energy	74.5
108	Fox Trail Solar	Brevard County, FL	1	Solar Energy	74.5
101	Long Creek Solar	Manatee County, FL	1	Solar Energy	74.5
100	Swallowtail Solar*	Walton County, FL	1	Solar Energy	74.5
127	Tenmile Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
	Total Nameplate PV:		**108**		**7,932**
		Total Units:	**169**		**36,946**
		Nameplate System Generation as of December 31, 2025 =			**36,946**
		Firm System Generation as of December 31, 2025 =			**30,457**

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Map Key "-" is shown for units that are located outside the State of Florida and therefore do not appear on the Map in Figure I.A.2.1.

FPL Bulk Transmission System

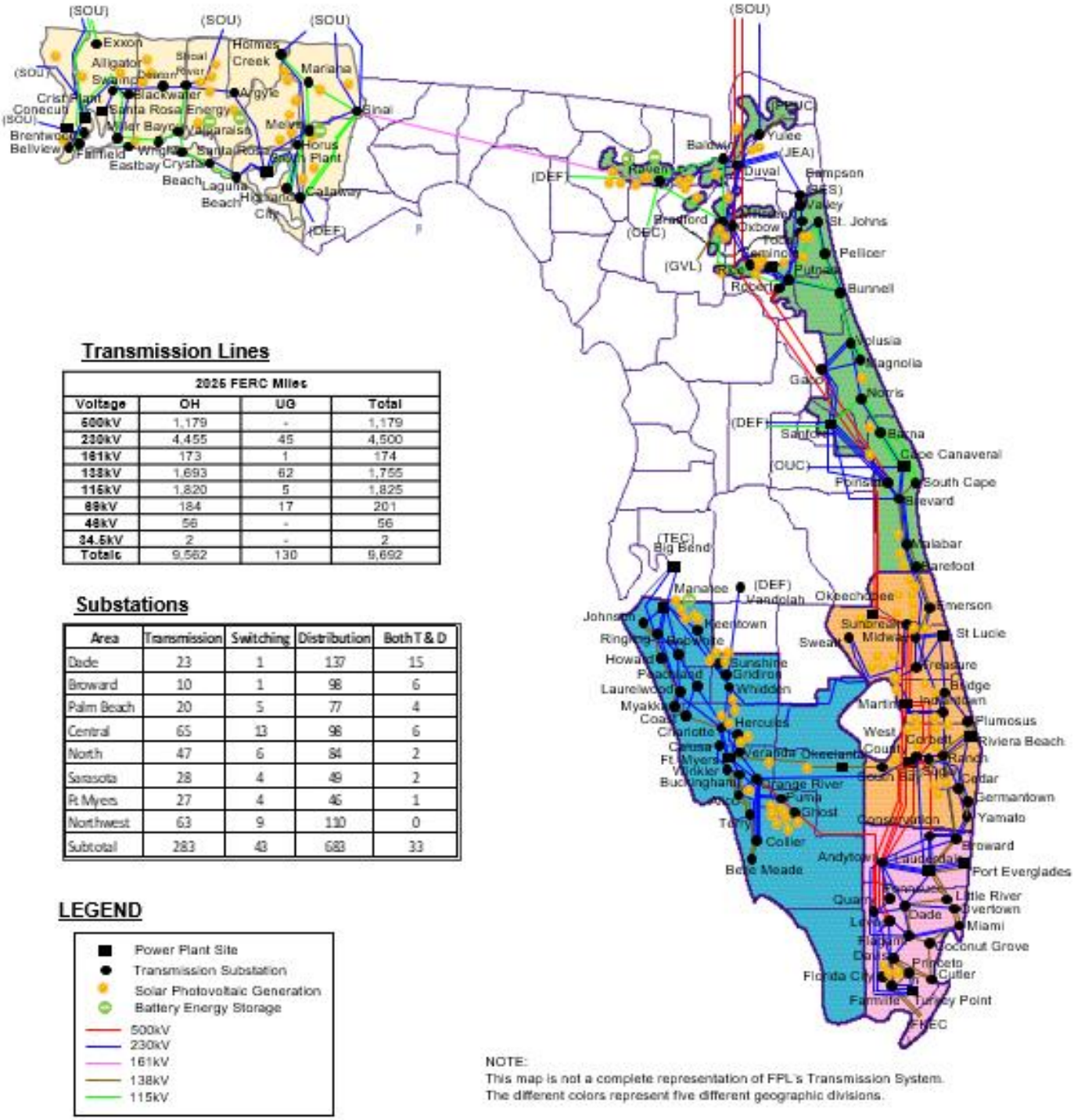


Figure I.A.2.2: FPL Bulk Transmission System

I.A.3 FPL - Capacity and Energy Power Purchases

Firm Capacity: Purchases from Qualifying Facilities (QF)

Firm capacity power purchases remain part of FPL's resource mix. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (*e.g.*, steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses solar, wind, waste, geothermal, or other renewable resources as its primary energy source.

FPL currently has a contract to purchase firm capacity and energy from the Broward South qualifying facility during the ten-year reporting period of this Site Plan. The 2025 actual and 2026-2035 projected contributions from these facilities are shown in Table I.A.3.1, Table I.A.3.2, and Table I.A.3.3.

Firm Capacity: Purchases from Utilities

FPL currently does not have any firm purchases from other utilities planned.

Firm Capacity: Other Purchases

FPL has four other firm capacity purchase contracts. Two of these contracts are with the Palm Beach Solid Waste Authority, and two are with Morgan Stanley Capital Group's Kingfisher I and Kingfisher II wind projects. Table I.A.3.2 and I.A.3.3 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from cogeneration and small power production facilities including energy from three solar PV facilities. The lower half of Table I.A.3.1 shows the amount of energy purchased in 2025 from these facilities along with the amount of energy purchased from customer-sited generation.

Table I.A.3.1: FPL's Purchased Power Resources by Contract (as of December 31, 2025)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
Broward South Landfill (firm)	Broward	Solid Waste	3.5
		Total:	3.5
II. Purchases from Utilities & IPP			
Santa Rosa, Southern Company Services		Natural Gas	230
Palm Beach SWA - REF 1	Palm Beach	Solid Waste	40
Palm Beach SWA - REF 2	Palm Beach	Solid Waste	70
MSCG - Kingfisher I	Oklahoma	Wind	53
MSCG - Kingfisher II	Oklahoma	Wind	28
		Total:	421
	Total Net Firm Generating Capability:		**425**

Non-Firm Energy Purchases (MWH)			
Project	**County**	**Fuel**	**Energy (MWH) Delivered to FPL in 2025**
Miami Dade Resource Recovery [1/]	Dade	Solid Waste	-
Broward South Landfill (as-available) [1/]	Broward	Solid Waste	90,290
Lee County Solid Waste[1/]	Lee	Solid Waste	25,086
Next Era energy Resources - Brevard Landfill [1/]	Brevard	Landfill Gas	22,459
Florida Crystals - Okeelanta [1/]	Palm Beach	Bagasse/Wood	46,304
Waste Management Renewable Energy - Collier Landfill [1/]	Collier	Landfill Gas	4,093
Next Era Energy Resources - Seminole Landfill [1/]	Seminole	Landfill Gas	10,243
Tropicana - Bradenton	Manatee	Natural Gas	14,348
Georgia Pacific Palatka Mill	Putnam	Paper by-product	7,948
Aria Energy - Sarasota Landfill [1/]	Sarasota	Landfill Gas	2,374
Waste Management Renewable Energy - Broward Landfill [1/]	Broward	Landfill Gas	3,600
Fortistar - Charlotte Landfill [1/]	Charlotte	Landfill Gas	-
Customer Owned PV & Wind [1/]	Various	PV/Wind	783,082
International Paper Company [1/]	Escambia	Biomass	985
Ascend Performance Materials	Escambia	Natural Gas	41,417
Gulf Coast Solar Center I , II, III[1/]	Vaarious	Sun	234,030
Total Energy from Renewable Non-Firm Purchases Delivered to FPL in 2025 [1/]:			**1,230,494**
Total Energy from All Non-Firm Purchases Delivered to FPL in 2025:			**1,286,259**

1/ These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 9, column 6.

Table I.A.3.2: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Broward South Landfill	01/01/93	12/31/26	1.4	0	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	0	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0	0	0	0	0	0	0	0	0
QF Purchases Subtotal:			**3.5**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
None	-	-	-	-	-	-	-	-	-	-	-	-
Utility Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**3.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Palm Beach SWA - REF1 1/	01/01/12	04/01/32	40	40	40	40	40	40	40	0	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	0	0
MSCG - Kingfisher I 2/	01/01/17	12/31/35	53	53	53	53	53	53	53	53	53	53
MSCG - Kingfisher II 2/	01/01/17	12/31/35	28	28	28	28	28	28	28	28	28	28
Gulf Solar PPAs 3/	11/17/14	12/31/42	48	48	48	48	47	47	47	47	46	46
Other Purchases Subtotal:			**239**	**239**	**239**	**239**	**238**	**238**	**238**	**198**	**127**	**127**
Total "Non-QF" Purchases =			**239**	**239**	**239**	**239**	**238**	**238**	**238**	**198**	**127**	**127**

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer Firm Capacity Purchases Total MW:	**243**	**239**	**239**	**239**	**238**	**238**	**238**	**198**	**127**	**127**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".

2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.

3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermitent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

Table I.A.3.3: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Broward South Landfill	01/01/93	12/31/26	1.4	0	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	0	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0	0	0	0	0	0	0	0	0
QF Purchases Subtotal:			**3.5**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
None	-	-	-	-	-	-	-	-	-	-	-	-
Utility Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**3.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Santa Rosa, SCS	06/01/24	2/29/2026	230	0	0	0	0	0	0	0	0	0
Palm Beach SWA - REF1 [1/]	01/01/12	04/01/32	40	40	40	40	40	40	40	0	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	70	0
MSCG - Kingfisher I [2/]	01/01/17	12/31/35	71	71	71	71	71	71	71	71	71	71
MSCG - Kingfisher II [2/]	01/01/17	12/31/35	38	38	38	38	38	38	38	38	38	38
Gulf Solar PPAs [3/]	11/17/14	12/31/42	0	0	0	0	0	0	0	0	0	0
Other Purchases Subtotal:			**449**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**	**109**
Total "Non-QF" Purchases =			**449**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**	**109**

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Winter Firm Capacity Purchases Total MW:	**453**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**	**109**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".

2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.

3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermitent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

I.A.4 Demand-Side Management (DSM)

FPL has continually explored and implemented cost-effective DSM programs since 1978, and it has consistently been among the leading utilities nationally in achieving substantial DSM efficiencies. These programs include innovative conservation/energy efficiency and load management initiatives. In the FPL service area, the company's DSM efforts through the end of 2025 have resulted in a cumulative Summer peak reduction of 5,771 MW at the generator and an estimated cumulative energy savings of 104,839 Gigawatt-Hours (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2025 have eliminated the need to construct the equivalent of approximately sixty-nine (69) new 100 MW generating units. Also, it is important to note that FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers by using the Rate Impact Measure (RIM) cost-effectiveness screening calculation approach.

In 2024, the FPSC set DSM Goals for the years 2025 through 2034 for FPL and the other Florida utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). In 2025, FPL filed for and obtained FPSC approval for its DSM Plan with which it intends to meet the DSM Goals. In this Site Plan, FPL assumes that the annual reduction values for Summer MW, Winter MW, and energy (MWh) set forth in the DSM Goals order (Order No. PSC-2024-0505-FOF-EG) will be met as shown in various schedules presented in this Site Plan.

I.A.5 Existing Generating Units in FPL's Service Area

Schedule 1 presents the generating capacity in FPL's service area as of December 31, 2025.

Schedule 1: FPL Existing Generating Facilities as of December 31, 2025

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport.		Alt. Fuel		Actual/		Net Capability [1/]		Firm Capability [2/]	
Plant Name	Unit No.	Area / Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Anhinga Solar [2/]		FPL Clay County 29.88213, -81.67618									74,500	74.5	74.5	1.84	28.09
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.84	28.09
Apalachee Solar [2/]		FPL NWFL Jackson County 30.76055, -85.06952									74,500	74.5	74.5	0.06	36.44
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.06	36.44
Babcock Preserve Solar [2/]		FPL Charlotte County 32,33/41S/26E : 4/42S/26E									74,500	74.5	74.5	0.00	36.30
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	36.30
Babcock Ranch Solar [2/]		FPL Charlotte County 29,31,32/41S/26E									74,500	74.5	74.5	0.00	33.33
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	33.33
Barefoot Bay Solar [2/]		FPL Brevard County 1, 10, 15,16/30S/38E									74,500	74.5	74.5	0.00	38.13
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	38.13
Beautyberry Solar [2/]		FPL Hendry County 26.373000, -81.026000									74,500	74.5	74.5	3.31	30.89
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.31	30.89
Big Juniper Battery Storage		FPL NWFL Santa Rosa County 30.639000, -86.925000									74,500	74.5	74.5	74.50	74.50
	1		BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.50	74.50
Big Juniper Solar [2/]		FPL NWFL Santa Rosa County 30.639000, -86.925000									74,500	74.5	74.5	0.05	37.67
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.05	37.67
Big Water Solar [2/]		FPL Okeechobee County 27.44193, -80.80183									74,500	74.5	74.5	2.06	20.03
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	2.06	20.03
Blackwater Solar [2/]		FPL NWFL Santa Rosa County 30.64691, -86.93821									74,500	74.5	74.5	0.01	27.67
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.01	27.67
Blue Cypress Solar [2/]		FPL Indian River County 16/33S/38E									74,500	74.5	74.5	0.00	36.75
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	36.75
Blue Heron Solar [2/]		FPL Hendry County 28,33/43S/32E									74,500	74.5	74.5	0.00	36.44
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	36.44
Blue Indigo Solar [2/]		FPL NWFL Jackson County 2/5N/12W : 35,36/6N/12W									74,500	74.5	74.5	0.00	46.55
	1		PV	Solar	Solar	N/A	N/A	--	Mar-20	Unknown	74,500	74.5	74.5	0.00	46.55
Blue Springs Solar [2/]		FPL NWFL Jackson County 36/5N/9W									74,500	74.5	74.5	0.02	38.73
	1		PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.02	38.73
Bluefield Preserve Solar [2/]		FPL St. Lucie County 27.24354, -80.67097									74,500	74.5	74.5	1.91	21.58
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.91	21.58

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport.		Alt. Fuel		Actual/		Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area / Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Buttonwood Solar [2]		FPL St. Lucie County 27.548000, -80.672000									74,500	74.5	74.5	2.19	33.49
	1		PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.19	33.49
Caloosahatchee Solar [2]		FPL Hendry County 26.752000, -81.180000									74,500	74.5	74.5	2.22	28.35
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.22	28.35
Canoe Battery Storage		FPL NWFL Okaloosa County 30.680000, -86.782000									74,500	74.5	74.5	74.5	74.5
	1		BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Canoe Solar [2]		FPL NWFL Okaloosa County 30.680000, -86.782000									74,500	74.5	74.5	0.05	37.75
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.05	37.75
Cape Canaveral		FPL Brevard County 19/23S/36E									1,418,000	1,418	1,290	1,418	1,290
	3		CC	NG	FO_2	PL	TK	Unknown	Apr-13	Unknown	1,418,000	1,418	1,290	1,418	1,290
Cattle Ranch Solar [2]		FPL DeSoto County 19,24,25/36S/26E									74,500	74.5	74.5	0.00	35.49
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	35.49
Cavendish Solar [2]		FPL Okeechobee County 27.628, -80.80317									74,500	74.5	74.5	4.25	29.38
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	4.25	29.38
Cedar Trail Solar [2]		FPL NWFL Baker County 30.322000, -82.192000									74,500	74.5	74.5	0.31	23.01
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.31	23.01
Chautauqua Solar [2]		FPL NWFL Walton County 30.87576, -86.20813									74,500	74.5	74.5	0.10	40.08
	1		PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.10	40.08
Chipola Battery Storage		FPL NWFL Calhoun County 30.45643, -85.27719									74,500	74.5	74.5	74.5	74.5
	1		BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Chipola Solar [2]		FPL NWFL Calhoun County 30.45643, -85.27719									74,500	74.5	74.5	0.04	33.99
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.04	33.99
Citrus Solar [2]		FPL DeSoto County 35/36S/25E : 2/37S/25E									74,500	74.5	74.5	0.00	36.67
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	36.67
Coral Farms Solar [2]		FPL Putnam County 27,28,33,34/8S/24E									74,500	74.5	74.5	0.00	32.42
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	32.42
Cotton Creek Solar [2]		FPL NWFL Jackson County 7/4N/8W									74,500	74.5	74.5	0.03	39.11
	1		PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.03	39.11
Cypress Pond Solar [2]		FPL NWFL Washington County 30.59444, -85.83008									74,500	74.5	74.5	0.16	37.25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.16	37.25

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport.		Alt. Fuel Days		Actual/ Expected		Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Use	Commercial In-Service Month/Year	Retirement Month/Year	Gen.Max. Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Dania Beach Clean Energy Center		FPL	Broward County 30/50S/42E								1,252,000	1,252	1,246	1,252	1,246
	7		CC	NG	FO_2	PL	TK	Unknown	Jan-22	Unknown	1,252,000	1,252	1,246	1,252	1,246
DeSoto Solar [2]		FPL	DeSoto County 27/36S/25E								25,000	25	25	0.66	9.38
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	25,000	25	25	0.66	9.38
Discovery Solar [2]		FPL	Brevard County 25,35,36/22S/36E								74,500	74.5	74.5	1.08	36.88
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.08	36.88
Echo River Battery Storage		FPL	Suwannee County 24,25,19/2S/14E : 30/2S/15E								30,000	30.0	30.0	30.0	30.0
	1		BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0
Echo River Solar [2]		FPL	Suwannee County 24,25,19/2S/14E : 30/2S/15E								74,500	74.5	74.5	0.00	40.19
	1		PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	40.19
Egret Solar [2]		FPL	Baker County 26,27/2S/21E								74,500	74.5	74.5	0.82	38.39
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.82	38.39
Elder Branch Solar [2]		FPL	Manatee County 18, 33S, 21E								74,500	74.5	74.5	2.38	32.20
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	2.38	32.20
Etonia Creek Solar [2]		FPL	Putnam County 29.76723, -81.77749								74,500	74.5	74.5	1.38	33.63
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.38	33.63
Everglades Solar [2]		FPL	Miami-Dade County 25.54255, -80.55434								74,500	74.5	74.5	3.07	23.29
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	3.07	23.29
Fawn Solar [2]		FPL	Martin County 27.05476, -80.37958								74,500	74.5	74.5	2.80	34.05
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	2.80	34.05
First City Solar [2]		FPL NWFL	Escambia County 30.91993, -87.34002								74,500	74.5	74.5	0.00	28.12
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	28.12
Flowers Creek Solar [2]		FPL NWFL	Calhoun County 30.57013, -85.03932								74,500	74.5	74.5	0.04	32.02
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.04	32.02
Fort Drum Solar [2]		FPL	Okeechobee County 2,11,13/33S/35E								74,500	74.5	74.5	1.01	33.21
	1		PV	Solar	Solar	N/A	N/A	Unknown	Aug-21	Unknown	74,500	74.5	74.5	1.01	33.21
Fort Myers		FPL	Lee County 35/43S/25E								2,911,000	2,911	2,776	2,911	2,776
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,920,000	1,920	1,822	1,920	1,822
	3		CT	NG	FO_2	TK	TK	Unknown	Jun-03	Unknown	868,000	868	852	868	852
	1, 9		GT	FO_2	No	WA	No	Unknown	May-74	Unknown	123,000	123	102	123	102

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.

2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport.		Alt. Fuel Days	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
ırmile Creek Battery Storage		FPL NWFL	Calhoun County												
			30.441000, -85.276000								74,500	74.5	74.5	74.5	74.5
	1		BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Fourmile Creek Solar [2]		FPL NWFL	Calhoun County												
			30.441000, -85.276000								74,500	74.5	74.5	0.21	39.50
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.21	39.50
Fox Trail Solar [2]		FPL	Brevard County												
			27.84, -80.682								74,500	74.5	74.5	1.97	35.49
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	1.97	35.49
Georges Lake Solar [2]		FPL	Putnam County												
			29.760000, -81.765000								74,500	74.5	74.5	0.69	22.15
	1		PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.69	22.15
Ghost Orchid Solar [2]		FPL	Hendry County												
			4,5 47S, 33E								74,500	74.5	74.5	1.94	33.64
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.94	33.64
Green Pasture Solar [2]		FPL	Charlotte County												
			27.023, -81.777								74,500	74.5	74.5	1.35	32.13
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	1.35	32.13
Grove Solar [2]		FPL	Indian River County												
			29, 33S, 37E								74,500	74.5	74.5	1.92	35.20
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.92	35.20
Gulf Clean Energy Center		FPL NWFL	Escambia County												
			25/1N/30W								1,901,000	1,892	1,878	1,892	1,878
	4		ST	NG	--	PL	--	--	Jul-59	4th Q 2029	75,000	72	72	72	72
	5		ST	NG	--	PL	--	--	Jun-61	4th Q 2029	75,000	72	72	72	72
	6		ST	NG	--	PL	--	--	May-70	Unknown	315,000	312	312	312	312
	7		ST	NG	--	PL	--	--	Aug-73	Unknown	496,000	496	496	496	496
	8		CT	NG	--	PL	--	--	Dec-21	Unknown	940,000	940	926	940	926
Hammock Solar [2]		FPL	Hendry County												
			34/43S/30E : 3,4,9,10/44S/30E								74,500	74.5	74.5	0.00	34.00
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	34.00
Hawthorne Creek Solar [2]		FPL	DeSoto County												
			27.086000, -81.836000								74,500	74.5	74.5	2.07	32.04
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	2.07	32.04
Hendry Isles Solar [2]		FPL	Hendry County												
			26.749000, -81.192000								74,500	74.5	74.5	1.92	17.88
	1		PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	1.92	17.88
Hibiscus Solar [2]		FPL	Palm Beach County												
			2/43S/40E								74,500	74.5	74.5	0.00	36.18
	1		PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	36.18
Hog Bay Solar [2]		FPL	DeSoto County												
			27.082, -81.842								74,500	74.5	74.5	1.34	31.05
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	1.34	31.05
Hollowpaw Solar [2]		FPL	Palm Beach County												
			26.77617,-80.41104								74,500	74.5	74.5	2.98	33.39
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	2.98	33.39

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.

2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel		Alt. Fuel		Actual/		Net Capability [1]		Firm Capability [2]	
	Unit			Fuel	Transport			Days	Commercial	Expected	Gen.Max.	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	MW	MW	MW	MW
Honeybell Solar [2]		FPL	Okeechobee County												
			27.522000, -80.744000									74,500	74.5	74.5	2.18	32.60
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.18	32.60
Horizon Solar [2]		FPL	Alachua County												
			25,35,36/9S/22E : 30, 31/9S/23E									74,500	74.5	74.5	1.03	36.37
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	1.03	36.37
Ibis Solar [2]		FPL	Brevard County												
			27.853000, -80.682000									74,500	74.5	74.5	3.02	35.12
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.02	35.12
Immokalee Solar [2]		FPL	Collier County												
			4, 9, 16, 46S, 29E									74,500	74.5	74.5	2.48	32.76
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	2.48	32.76
Indian River Solar [2]		FPL	Indian River County												
			30/33S/38E									74,500	74.5	74.5	0.00	36.46
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	36.46
Interstate Solar [2]		FPL	St. Lucie County												
			28,33/34S/39E									74,500	74.5	74.5	0.00	35.19
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	35.19
Kayak Battery Storage		FPL NWFL	Okaloosa County												
			30.704000, -86.700000									74,500	74.5	74.5	74.5	74.5
	1			BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Kayak Solar [2]		FPL NWFL	Okaloosa County												
			30.704000, -86.700000									74,500	74.5	74.5	0.00	29.07
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.00	29.07
Lakeside Solar [2]		FPL	Okeechobee County												
			28,29,32/37S/36E									74,500	74.5	74.5	1.15	34.91
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.15	34.91
Lansing Smith		FPL NWFL	Bay County												
			36/2S/15W									705,000	705	673	705	673
	3			CC	NG	--	PL	--	--	Apr-02	Unknown	665,000	665	641	665	641
	A			CT	LO	--	TK	--	--	May-71	4th Q 2027	40,000	40	32	40	32
Lauderdale		FPL	Broward County												
			30/50S/42E									1,228,400	1,218	1,224	1,218	1,224
	6			CT	NG	FO_2	PL	TK	Unknown	Dec-16	Unknown	1,155,000	1,145	1,155	1,145	1,155
	3, 5			GT	NG	FO_2	PL	TK	Unknown	Aug-70	Unknown	73,400	73	69	73	69
Loggerhead Solar [2]		FPL	St. Lucie County												
			21/37S/38E									74,500	74.5	74.5	0.00	35.38
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	35.38
Long Creek Solar [2]		FPL	Manatee County												
			27.412, -82.104									74,500	74.5	74.5	1.33	31.95
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	1.33	31.95
Magnolia Springs Solar [2]		FPL	Clay County												
			15,16,21,22/7S/26E									74,500	74.5	74.5	1.06	37.34
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.06	37.34

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport		Alt. Fuel	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Manatee Battery Storage		FPL Manatee County													
		1,12,13,24/33S/19E : 18,19/33S/20E									409,000	409	409	409	409
	1		BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	409,000	409	409	409	409
Manatee Solar [2]		FPL Manatee County													
		1,12,13,24/33S/19E : 18,19/33S/20E									74,500	74.5	74.5	0.00	36.56
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	36.56
Manatee		FPL Manatee County													
		18/33S/20E									2,986,000	1,348	1,246	1,348	1,246
	1 [3]		ST	NG	FO_6	PL	WA	Unknown	Oct-76	[3]	819,000	0	0	0	0
	2 [3]		ST	NG	FO_6	PL	WA	Unknown	Dec-77	[3]	819,000	0	0	0	0
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,348,000	1,348	1,246	1,348	1,246
Martin		FPL Martin County													
		30/39S/38E									2,385,000	2,403	2,223	2,403	2,223
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	538,000	538	487	538	487
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	520,000	538	487	538	487
	8		CC	NG	FO_2	PL	TK	Unknown	Jun-05	Unknown	1,327,000	1,327	1,249	1,327	1,249
Miami Dade Solar [2]		FPL Miami-Dade County													
		13/55S/38E									74,500	74.5	74.5	0.00	33.46
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	33.46
Mitchell Creek Solar [2]		FPL NWFL Escambia County													
		30.928510, -87.364140									74,500	74.5	74.5	0.00	28.65
	1		PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.00	28.65
Monarch Solar [2]		FPL Martin County													
		27.030740, -80.524800									74,500	74.5	74.5	2.80	27.75
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.80	27.75
Nassau Solar [2]		FPL Nassau County													
		2/1N/24E									74,500	74.5	74.5	1.01	36.48
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.01	36.48
Nature Trail Solar [2]		FPL Baker County													
		30.313000, -82.177000									74,500	74.5	74.5	1.32	38.53
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	1.32	38.53
Northern Preserve Solar [2]		FPL Baker County													
		13,18/3S/20E : 24/3S/21E									74,500	74.5	74.5	0.00	32.79
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	32.79
Norton Creek Solar [2]		FPL Madison County													
		30.383000, -83.327000									74,500	74.5	74.5	0.03	25.97
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.03	25.97
Okeechobee [4]		FPL Okeechobee													
		2/33S/35E									1,720,000	1,672	1,720	1,672	1,720
	1		CC	NG	FO_2	PL	TK	Unknown	Mar-19	Unknown	1,720,000	1,672	1,720	1,672	1,720
Okeechobee Solar [2]		FPL Okeechobee County													
		1,12,13/33S/35E									74,500	74.5	74.5	0.00	33.32
	1		PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	33.32
Orange Blossom Solar [2]		FPL Indian River County													
		19/33S/38E									74,500	74.5	74.5	1.25	36.46
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.25	36.46

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
3/ Manatee Units 1 & 2 are Winter Peaking ONLY units. They will only be manned and operated during an Extreme Winter event in which additional capacity is needed to meet load.
4/ As part of the Okeechobee Hydrogen Gas Pilot Program, a portion of the CO_2 generated from the unit is transferred to an electrolyzer where it is then converted into Hydrogen Gas.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel Transport		Alt. Fuel	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Orchard Solar [2]		FPL	Indian River/St. Lucie County													
			27.556000, -80.570000									74,500	74.5	74.5	4.22	36.17
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	4.22	36.17
Palm Bay Solar [2]		FPL	Brevard County													
			19,30/30S/37E									74,500	74.5	74.5	0.89	39.15
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	0.89	39.15
Pea Ridge		FPL NWFL	Santa Rosa County													
			15/1N/29W									15,000	15	12	15	12
	1			CT	NG	--	PL	--	--	May-98	4th Q 2031	5,000	5	4	5	4
	2			CT	NG	--	PL	--	--	May-98	4th Q 2031	5,000	5	4	5	4
	3			CT	NG	--	PL	--	--	May-98	4th Q 2031	5,000	5	4	5	4
Pecan Tree Solar [2]		FPL NWFL	Walton County													
			30.933000, -86.246000									74,500	74.5	74.5	0.05	40.29
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.05	40.29
Pelican Solar [2]		FPL	St. Lucie County													
			6,7/34S/38E									74,500	74.5	74.5	1.29	37.39
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.29	37.39
Perdido LFG		FPL NWFL	Escambia County													
												3,000	3	3	3	3
	1			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
	2			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
Pineapple Solar [2]		FPL	St. Lucie County													
			27.255000, -80.571000									74,500	74.5	74.5	3.08	32.72
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.08	32.72
Pink Trail Solar [2]		FPL	St. Lucie County													
			27.29783, -80.54214									74,500	74.5	74.5	2.52	21.25
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	2.52	21.25
Pioneer Trail Solar [2]		FPL	Volusia County													
			21/17S/32E									74,500	74.5	74.5	0.00	32.58
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	32.58
Port Everglades		FPL	City of Hollywood													
			23/50S/42E									1,333,000	1,333	1,237	1,333	1,237
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-16	Unknown	1,333,000	1,333	1,237	1,333	1,237
Prairie Creek Solar [2]		FPL	DeSoto County													
			27.045000, -81.809000									74,500	74.5	74.5	2.30	32.27
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.30	32.27
Redlands Solar [2]		FPL	Miami-Dade County													
			25.543, -80.547									74,500	74.5	74.5	0.65	24.57
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	0.65	24.57
Riviera Beach		FPL	City of Riviera Beach													
			33/42S/432E									1,406,000	1,406	1,290	1,406	1,290
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-14	Unknown	1,406,000	1,406	1,290	1,406	1,290

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel Transport		Alt. Fuel		Actual/		Net Capability [1]		Firm Capability [2]	
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Rodeo Solar [2]		FPL	DeSoto County													
			23,24,25,26,27/36S/25E									74,500	74.5	74.5	1.47	35.83
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	1.47	35.83
Sabal Palm Solar [2]		FPL	Palm Beach County													
			33/42S/40E									74,500	74.5	74.5	1.59	36.71
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jun-21	Unknown	74,500	74.5	74.5	1.59	36.71
Sambucus Solar [2]		FPL	Manatee County													
			27.449000, -82.064000									74,500	74.5	74.5	1.83	31.31
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	1.83	31.31
Sanford		FPL	Volusia County													
			16/19S/30E									2,556,000	2,556	2,418	2,556	2,418
	4			CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,278,000	1,278	1,209	1,278	1,209
	5			CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,278,000	1,278	1,209	1,278	1,209
Saw Palmetto Solar [2]		FPL NWFL	Bay County													
			30.4213, -85.44103									74,500	74.5	74.5	0.22	37.71
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.22	37.71
Sawgrass Solar [2]		FPL	Hendry County													
			20, 21, 28, 29, 47S, 33E									74,500	74.5	74.5	1.97	33.19
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.97	33.19
Scherer [5]		FPL NWFL	Monroe, GA													
												215,000	215	215	215	215
	3			ST	C	--	RR	--	--	Jan-87	4th Q 2034	215,000	215	215	215	215
Shirer Branch Battery Storage		FPL NWFL	Calhoun County													
			30.39891, -85.27975									74,500	74.5	74.5	74.5	74.5
	1			BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Shirer Branch Solar [2]		FPL NWFL	Calhoun County													
			30.39891, -85.27975									74,500	74.5	74.5	0.20	37.79
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.20	37.79
Silver Palm Solar [2]		FPL	Palm Beach County													
			26.788000, -80.352000									74,500	74.5	74.5	3.34	30.83
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.34	30.83
Southfork Solar [2]		FPL	Manatee County													
			26/33S/21E									74,500	74.5	74.5	0.00	40.63
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	40.63
Space Coast Solar [2]		FPL	Brevard County													
			13/23S/36E									10,000	10	10	0.12	3.54
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10	0.12	3.54
Sparkleberry Solar [2]		FPL NWFL	Escambia County													
			30.763000, -87.433000									74,500	74.5	74.5	0.16	38.28
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.16	38.28
Speckled Perch Solar [2]		FPL	Okeechobee County													
			27.28, -80.804									74,500	74.5	74.5	2.16	19.46
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	2.16	19.46

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
5/ Unit capabilities show n represent FPL NWFL's portion of Scherer Unit 3 (25%) located in Georgia.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport		Alt. Fuel	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1/]		Firm Capability [2/]	
Plant Name	Unit No.	Area Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
St. Lucie [6/]		FPL St. Lucie County 16/36S/41E									1,863,000	1,863	1,821	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,003,000	1,003	981	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	860,000	860	840	860	840
Sundew Solar [2/]		FPL St. Lucie County 17, 37S, 38E									74,500	74.5	74.5	1.99	35.61
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.99	35.61
Sunshine Gateway Battery Storage		FPL Columbia County 25,26,35,36/2S/15E : 31,32/5S/16E									30,000	30.0	30.0	30.0	30.0
	1		BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0
Sunshine Gateway Solar [2/]		FPL Columbia County 25,26,35,36/2S/15E : 31,32/5S/16E									74,500	74.5	74.5	0.00	36.84
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	36.84
Swallowtail Solar [2/]		FPL NWFL Walton County 30.92362, -86.23106									74,500	74.5	74.5	0.00	39.82
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	0.00	39.82
Sweetbay Solar [2/]		FPL Martin County 17,19/39S/39E									74,500	74.5	74.5	0.00	29.76
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	29.76
Tenmile Creek Battery Storage		FPL NWFL Calhoun County 30.499, -85.174									74,500	74.5	74.5	74.5	74.5
	1		BS	N/A	N/A	N/A	N/A	Unknown	Nov-25	Unknown	74,500	74.5	74.5	74.5	74.5
Tenmile Creek Solar [2/]		FPL NWFL Calhoun County 30.499, -85.174									74,500	74.5	74.5	0.00	29.77
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	0.00	29.77
Terrill Creek Solar [2/]		FPL Clay County 29.884000, -81.767000									74,500	74.5	74.5	1.39	34.71
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.39	34.71
Thomas Creek Solar [2/]		FPL Nassau County 30.51999, -81.88676									74,500	74.5	74.5	0.46	31.53
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-25	Unknown	74,500	74.5	74.5	0.46	31.53
Three Creeks Solar [2/]		FPL Manatee County 27.581000, -82.260000									74,500	74.5	74.5	2.14	33.46
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	2.14	33.46
Trailside Solar [2/]		FPL St. Johns County 25,36/8S/28E									74,500	74.5	74.5	1.01	39.08
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.01	39.08
Turkey Point		FPL Miami Dade County 27/57S/40E									3,085,000	3,085	2,981	3,085	2,981
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	859,000	859	837	859	837
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	866,000	866	844	866	844
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,360,000	1,360	1,300	1,360	1,300

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.

2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

6/ Total capability of St. Lucie 1 is 981 Summer/1,003 Winter MW. FPL's share of St. Lucie 2 is 840 Summer/860 Winter MW.
FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and excludes the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						Fuel Transport		Alt. Fuel	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1/]		Firm Capability [2/]	
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Pri.	Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Turnpike Solar [2/]		FPL	Indian River County												
			27.568000, -80.645000									74,500	74.5	74.5	3.17	35.09
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.17	35.09
Twin Lakes Solar [2/]		FPL	Putnam County												
			19,20,25/10S/24E : 30/10S/25E									74,500	74.5	74.5	0.95	37.96
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.95	37.96
Union Springs Solar [2/]		FPL	Union County												
			3,4,9,10/6S/20E : 33/5S/20E									74,500	74.5	74.5	0.81	37.97
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.81	37.97
West County		FPL	Palm Beach County												
			29/43S/40E									4,047,000	4,047	3,771	4,047	3,771
	1			CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	2			CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	3			CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,349,000	1,349	1,257	1,349	1,257
White Tail Solar [2/]		FPL	Martin County												
			27.080000, -80.379000									74,500	74.5	74.5	3.53	36.58
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.53	36.58
Wild Azalea Solar [2/]		FPL NWFL	Gadsden County												
			30.6758, -84.74033									74,500	74.5	74.5	0.25	39.26
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.25	39.26
Wild Quail Solar [2/]		FPL NWFL	Walton County												
			30.898050, -86.250070									74,500	74.5	74.5	0.07	42.04
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.07	42.04
Wildflower Solar [2/]		FPL	DeSoto County												
			25,26,/36S/25E									74,500	74.5	74.5	0.00	35.36
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	35.36
Willow Solar [2/]		FPL	Manatee County												
			2,3,10,11/35S/22E									74,500	74.5	74.5	1.28	34.89
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.28	34.89
Woodyard Solar [2/]		FPL	Hendry County												
			26.420000, -81.051000									74,500	74.5	74.5	3.11	29.55
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	3.11	29.55
Total Nameplate System Generating Capacity as of December 31, 2025 [7/] =												**38,265**	**36,946**	-	-	
Total Firm System Generating Capacity as of December 31, 2025 [8/] =												**-**	**-**	**30,448**	**30,457**	

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
7/ The Total Nameplate System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
8/ The System Firm Generating Capacity value shown includes only firm generating capacity.

(This page is intentionally left blank.)

CHAPTER II

Forecast of Electric Power Demand

(This page is intentionally left blank.)

II. Forecast of Electric Power Demand

II.A. Overview of the Load Forecasting Process

The load forecasting team developed the long-term forecasts of customers, sales, net energy for load (NEL), and peak demands presented in this 2026 Site Plan. These forecasts are utilized throughout this 2026 Site Plan and are key inputs in the resource planning analyses that led to the integrated resource plans presented in this document.

The forecasts are developed annually and use consistent methodologies for both the FPL Legacy and FPL NWFL areas. The forecasts for the integrated system are developed by combining the forecasts for the FPL Legacy and FPL NWFL areas. FPL has used the same methodology and approach for its long-term Site Plan forecasts since 2021. The load forecasting team will continue to evaluate and implement appropriate enhancements to the forecasting methodologies for upcoming forecasts as necessary.

The following pages describe how the forecasts of customers, sales, NEL, and peak loads were initially developed separately for the FPL Legacy and FPL NWFL areas and then combined into a single set of forecasts for the integrated system. This approach is required because the historical data for the integrated system was not available prior to FPL and Gulf Power's consolidation.

Similar to previous forecasts, the drivers for the forecasts include household growth, economic conditions, electricity prices, weather, and energy efficiency codes and standards. The forecasts for customers, energy sales, NEL, and summer peak demands are 50% probability (P50) forecasts, which means there is a 50% probability that actual results will be either higher or lower than the forecast.

The projections for population growth, Florida Gross State Product, and other economic variables are obtained from S&P Global, a leading economic forecasting firm that has been previously used by FPL. Additionally, the projections for electric vehicle adoption and impact come from Bloomberg New Energy Finance and Wood Mackenzie, while the projections for private solar adoption and impact are from Wood Mackenzie. Both Bloomberg and Wood Mackenzie are well known for their financial and energy forecasts. Using statistical models, these inputs are quantified in terms of their impact on the respective forecasts.

Weather is a key factor that affects energy sales and peak demand. The weather variables for use in the forecasting models are as follows:

1. The residential and commercial energy models incorporate heating degree hours and/or cooling degree hours. The threshold temperatures differ based on how each customer group responds to temperatures.
2. The Summer peak demand models incorporate minimum and maximum temperatures of the peak Summer day, while the Winter peak demand models incorporate minimum temperatures on the peak Winter day and the buildup of heating degree hours on the day prior to the peak day. Additional details are provided later in this chapter.

The weather variables used in the FPL models are based on a composite hourly temperature from the following weather stations: Miami, Fort Myers, Daytona Beach, and West Palm Beach. The temperatures for each weather station are weighted based on the energy sales associated with that region. The resulting composite temperatures are then used to derive the cooling degree hours and heating degree hours used in the energy models as well as the peak day temperatures used in the Summer and Winter peak demand models.

The weather variables used in the FPL NWFL models are based on the hourly temperatures from the Pensacola weather station. The Pensacola hourly temperatures are then used to derive the cooling degree hours and heating degree hours used in the energy models, the peak day cooling degree hours used in the Summer peak demand model, and the temperatures used in the Winter peak demand model.

II.B. Customer Forecasts

The customer forecasts for the integrated system for 2026 and beyond are the sum of the respective class-level customer forecasts for the FPL and FPL NWFL areas. The class-level customer forecasts were developed using a combination of regression models, exponential smoothing models, and inputs regarding wholesale contracts. The statistical models were developed using the software package MetrixND. The methods and tools used to develop the customer forecasts are consistent with those used in prior Site Plans, with routine updates to include additional historical data and updated economic projections, along with minor changes to model specifications.

The residential customer forecasts were developed using regression models which include Florida Gross State Product, lag dependent variables, and binary variables. The commercial customer

models were segmented by rate code, and the models were a combination of regression models and exponential smoothing models. The commercial regression models included employment for Florida, Florida Gross State Product, lag dependent variables, and binary variables. The industrial customer models were also segmented by rate code, and the models were a combination of a regression model and exponential smoothing models. The industrial regression model included housing starts, lagged dependent variables, and a binary variable. The customer forecasts for the Metro and Other customer classes were developed by applying the last known value since little to no changes are expected in these customer classes. The Street & Highway Lighting forecast was developed by the FPL lighting team. Resale (wholesale) customers were forecasted based on known or likely wholesale contracts.

Total customer growth is projected to grow at an average annual rate of 1.1% during the forecast period. The primary driver of customer growth is population growth.

II.C. Energy Sales Forecasts

Energy sales forecasts for the integrated system for 2026 and beyond are the sum of the respective class-level energy sales forecasts for the Legacy FPL and FPL NWFL areas. First, forecasts were developed for the major revenue classes, wholesale energy sales, and losses. Next, energy adjustments were calculated for factors such as electric vehicles and private solar, and were applied to the class-level energy sales forecasts. Finally, these forecasts were aggregated to arrive at NEL forecasts (a bottom-up approach). The statistical models used in the energy sales forecasting process were developed using the software package MetrixND.

The methods and tools used to develop the energy sales forecasts were consistent with those used for prior Site Plans, with routine updates to include additional historical data and updated economic projections, along with minor updates to model specifications.

1. Residential Sales

The residential energy sales forecasts were developed using econometric models. Residential energy sales were first expressed as monthly use per customer per billing day. The forecasted energy use per customer per billing day was then multiplied by the projected number of billing days and customers to arrive at the residential billed energy sales forecast. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecast. The residential energy use per customer per billing day models include variables for cooling degree hours, heating degree hours, the moving average of real electricity price

increases over time, energy savings from changes to energy efficiency codes and standards, binary variables, and autoregressive terms. The residential energy sales forecasts were also adjusted to reflect the anticipated impacts of continued adoption of electric vehicles and private solar.

2026 residential energy sales for the integrated system are projected to be 54.9% of sales to ultimate consumers and are projected to grow at an average annual rate of 1.7% over the forecast period.

2. **Commercial Sales**

The commercial energy sales forecasts were also developed using econometric models where the energy sales were expressed as monthly use per customer per billing day. The forecasted energy use per customer per billing day was multiplied by the projected number of billing days and customers to arrive at the commercial billed energy sales forecasts. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecasts. The commercial energy use per customer forecasts were developed using separate models based on rate code. The two FPL models were for small/medium customers (commercial customers on energy only and demand rates less than 500 kilowatt) and large customers (commercial customers on demand rates of 500 kW or higher). The FPL NWFL models were for small customers (commercial customers on General Service or GS rates) and large customers (commercial customers on demand rates of 25 kW or higher). The commercial energy sales models utilize variables for cooling degree hours, heating degree hours, housing starts, employment, the moving average of real electricity price increases over time, energy savings from changes to energy efficiency codes and standards, binary variables, and autoregressive terms. The commercial lighting sales forecast was developed using inputs from FPL's lighting team. These forecasts are then added together to arrive at the total commercial sales forecast. The total commercial energy sales forecast was also adjusted to reflect the impact of private solar.

2026 commercial energy sales for the integrated system are projected to be 41.1% of sales to ultimate consumers and are projected to grow at an average annual rate of 0.3% over the forecast period.

3. **Industrial Sales**

The projected industrial class energy sales were also forecasted using both econometric and exponential smoothing models. Industrial energy sales were expressed as either energy sales per customer or energy sales per customer per bill day. The resulting forecasts were then multiplied by bill days and/or customers to arrive at the billed energy sales forecasts. Energy usage for FPL's small and medium industrial customers (industrial customers on rate GS) was forecasted using an econometric model which included a lag dependent variable and binary variables while energy usage for large industrial customers was forecasted using an exponential smoothing model. FPL NWFL's industrial energy usage was forecasted using an exponential smoothing model. The industrial lighting sales forecast was developed using inputs from FPL's lighting team. These forecasts were then added together to arrive at the total industrial sales forecast. The total industrial sales forecast was adjusted to reflect the impact of very large demand, high load factor customers projected to take service on the FPL system during the planning period beginning in 2028.

For potential new customers with significant or unique load requirements, FPL's historical practice is to include the associated load in the forecast only after FPL and the customer have reached a definitive agreement or other binding commitment to extend service to the customer. Currently, there are no definitive agreements in place or other binding commitments between FPL and any large power users. However, based on discussions with potential large power users, FPL believes there is a high probability for customers with significant load requirements to be served on the FPL system beginning in 2028 with total load growing to approximately 3 GW by 2035.

2026 industrial energy sales for the integrated system are projected to be 3.5% of sales to ultimate consumers and are projected to grow at an average annual rate of 21.1% over the forecast period.

4. **Railroad & Railways Sales and Street and Highway Sales**

The Railroad & Railway class consists solely of Miami-Dade County's Metrorail system. The Railroad & Railways sales forecast was developed using a regression model which included monthly binary variables and autoregressive terms.

The forecast inputs for Street and Highway sales forecasts were provided by FPL's lighting team.

5. **Other Public Authority Sales**

This class consists of a sports field rate schedule (which is closed to new customers) and one governmental account. The forecast for this class was developed using an exponential smoothing model.

6. **Total Sales to Ultimate Customer**

The sales forecasts for each of the revenue classes were each summed to produce the Total Sales to Ultimate Customer forecasts.

7. **Sales for Resale**

Sales for Resale (wholesale) customers are comprised of sales to municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of electricity. Instead, they resell this electricity to their own customers.

The Sales for Resale forecast includes wholesale loads served under full and partial-requirements contracts that provide other utilities all, or a portion of, their load requirements at a level of service equivalent to FPL's own native load customers. There are fourteen customers in this class: Florida Keys Electric Cooperative, Lee County Electric Cooperative, New Smyrna Beach, Wauchula, Homestead, Quincy, Moore Haven, Florida Public Utilities Company, Blountstown, Alachua, Jacksonville Electric Authority, Bartow, PowerSouth, and Dalton.

Florida Keys Electric Cooperative: Service began May 2011 under a long-term, full-requirements contract that continues through 2032, with an option to extend through 2052.

Lee County Electric Cooperative: Service began in 2010. The current full-requirements contract began in 2014 and continues through 2033, with an option to extend through 2053.

New Smyrna Beach: Sales began in February 2014 and continue through December 2033, with a three-year extension option.

Wauchula: Sales began in January 2024 and continue through December 2030.

Homestead: Sales began in August 2015 and continue through December 2028.

Quincy: Sales began in January 2016 and continue through December 2027.

Moore Haven: Sales began in July 2016 and continue through December 2035.

Florida Public Utilities Company: Sales began in January 2018 and continue through December 2029.

Blountstown: Sales began in May 2022 and continue through April 2027.

Alachua: Sales began in April 2022 and continue through March 2029.

Jacksonville Electric Authority: Sales began in January 2022 and continue through December 2041.

Bartow: Sales began in January 2024 and continue through December 2030.

PowerSouth: Sales will begin in December 2026 and continue through February 2029.

Dalton: Sales will begin in January 2028 and continue through December 2034.

II.D. Net Energy for Load (NEL)

The NEL forecasts for the years 2026 through 2035 are the sums of the retail energy, wholesale energy, and losses forecasts. Through the use of the energy efficiency variable, the retail energy sales forecast includes the impacts from major energy efficiency codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent lamps (CFL) and light emitting diodes (LED). The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005, and, from that year forward, their cumulative impact on NEL for the integrated system is projected to be a reduction of approximately 10,550 GWh by 2035. This represents a 5.5% reduction in what the forecasted NEL for 2035 would have been, absent these codes and standards. The estimated impacts from codes and standards are based on the energy efficiency variables in the respective energy models.

Adjustments were made to the NEL forecast to address the impact of incremental private (customer-owned) solar and for the additional load projected to be added due to the incremental

adoption of new plug-in EVs during the forecast period. The impact of private solar and EV adoption on the NEL forecast for the integrated system is projected to be a net increase of approximately 5,400 GWh by 2035, compared to a net increase of approximately 2,800 GWh shown in the prior Site Plan. The net increase relative to the prior Site Plan primarily reflects updated projections for private solar and EV adoption that account for expected changes in federal tax credit availability under the OBBBA enacted and signed into law in 2025.

II.E. System Peak Forecasts

The rate of absolute growth in peak load is a function of the size of the customer base, projected economic conditions, and energy efficiency codes and standards. The peak load forecast models capture these behavioral relationships. The peak load forecasts also reflect changes in load from private solar, plug-in EVs, economic development riders, and wholesale requirements contracts.

The monthly peak loads for the integrated system from 2026 and beyond are the highest hourly demand from the forecasted system hourly load forecast, which was developed by first adjusting FPL NWFL's load to reflect Eastern time zone and then summing the forecasted system hourly loads for the systems. The integrated system peak load forecast reflects the growth in peak load and includes the expected reduction to the peak demand for the integrated system that results from load diversity.

When viewed as separate systems or regions, the loads peak at different times which results in load diversity, primarily due to the FPL NWFL system being located in a different time zone than the rest of the FPL system. The benefit of load diversity is a reduction to the integrated system peak demand. By 2035, the peak demand reductions from load diversity are projected to be 112 MW in the Summer and 568 MW in the Winter.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of CFLs and LEDs. The impact from these energy efficiency standards began in 2005, and their cumulative reduction, from that year, on the integrated Summer peak is projected to reach approximately 8,300 MW by 2035.

For the integrated system, the cumulative 2035 impacts from these energy efficiency codes and standards are projected to effectively reduce the Summer peak by approximately 23% and the Winter peak by approximately 6% for that year. From the end of 2025 through 2035, the projected

incremental impacts from these energy efficiency codes and standards are a reduction on the Summer peak of approximately 1,940 MW and a reduction on the Winter peak of approximately 420 MW.

As noted previously, the forecasts were also adjusted for the estimated load impacts from private solar and plug-in EVs. The combined impact of private solar and plug-in EVs is projected to increase peak load on the FPL's system by approximately 1,050 MW in the Summer and 760 MW in the Winter by the end of 2035.

The forecasting methodologies for Summer, Winter, and monthly system peaks are discussed below.

1. **System Summer Peak**

The Summer peak demand forecast for the integrated system is the highest hourly demand during the Summer months from the integrated system hourly forecast which was developed by summing the forecasted system hourly loads for FPL and FPL NWFL. This approach ensures the Summer peak demand forecast for the integrated system reflects the growth in Summer peak load while reflecting the previously mentioned peak demand reduction associated with load diversity. The Summer peak demand for the integrated system is projected to occur in August.

The Summer peak forecasts were developed using econometric models where the peak loads were expressed as Summer peak load per customer and the resulting projected peak loads per customer were multiplied by the forecast number of customers to arrive at the Summer peak load forecasts. The models included variables for weather, employment or income, and peak load reductions from change in energy efficiency codes and standards. The peak loads were then adjusted to account for the expected changes in loads resulting from private solar, plug-in EVs, wholesale requirements, and the expected addition of large loads to derive FPL's system Summer peak.

2. **System Winter Peak**

The Winter peak forecast presented in this Site Plan is the highest hourly demand during the Winter months from the integrated system hourly forecast, which was developed by summing the forecasted system hourly loads for FPL and FPL NWFL. This approach ensures the Winter peak demand forecast for the integrated system reflects the growth in Winter peak while

reflecting the Winter peak demand reduction associated with load diversity. The Winter peak demand for the integrated system is projected to occur in January.

FPL developed P50 normal weather Winter peak loads using two econometric models, one each for the FPL and FPL NWFL areas. The model for FPL expressed Winter peak load as peak load per customer and included weather variables, employment, and binary variables. The projected peak load per customer was multiplied by the customer forecast to arrive at the projected Winter peak load. The projections were then adjusted for the expected changes in loads resulting from private solar, plug-in EVs, wholesale requirements, and the expected addition of large loads to arrive at the forecasted normal weather Winter peak load. The model for FPL NWFL expressed Winter peak load as peak load and included weather, population, and peak load reductions from changes in energy efficiency codes and standards. The projected load was then adjusted for the expected changes in loads resulting from private solar and plug-in EVs to arrive at the forecasted normal weather Winter peak load.

3. **Monthly Peak Forecasts**

The forecasting process for the monthly peaks assumes the Summer peak for FPL occurs in the month of August while the Summer peak for FPL NWFL occurs in the month of July. It also assumes that the Winter peak for both areas occur in the month of January. Finally, the remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual Summer peak.

The monthly peak demand forecasts for the integrated system for 2026 and beyond are the highest hourly demand by month from the integrated system hourly forecasts. This approach ensures the integrated monthly peak demand forecast reflects the growth in monthly peaks as well as the monthly peak demand reductions associated with load diversity. The Summer peak for the integrated FPL system occurs in August because of the large size of the FPL Legacy area. The Winter peak for the integrated FPL system occurs in January.

II.F. Hourly Load Forecast

The forecasted values for system hourly load on the integrated system were the summation of the FPL Legacy and FPL NWFL hourly load for the period. The FPL NWFL system hourly load was adjusted from Central to Eastern time zone to be consistent with FPL Legacy's system hourly load.

Forecasted values for FPL's system hourly load were developed using a system load forecasting program named MetrixLT. This model uses years of historical FPL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of FPL's monthly peaks and energy.

Forecasted values for FPL NWFL's system hourly load were also developed using MetrixLT, which uses historical FPL NWFL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of FPL NWFL's monthly peaks and energy.

II.G. Uncertainty

Uncertainty is inherent in the load forecasting process. This uncertainty can result from a number of factors, including unexpected changes in consumer behavior, structural shifts in the economy, economic/business cycles, and fluctuating weather conditions. Large weather fluctuations can and frequently do result in significant deviations between actual and forecasted peak demands. In particular, Winter peak demands have experienced significantly greater volatility than those observed for the Summer peak or NEL.

The inherent uncertainty in load forecasting is addressed in different ways regarding the overall resource planning and operational planning work. With respect to resource planning work, the utilization of a 20% total reserve margin (TRM) criterion, a LOLP criterion of 0.1 days per year, and a 10% GRM criterion are designed to maintain reliable electric service for customers in light of forecasting and other uncertainties. In addition, FPL's Winter peak demands have experienced significantly greater volatility than the Summer peak or NEL, and this greater volatility results in additional risks to FPL's ability to serve winter load. FPL continues to analyze system impacts of Winter peak demands due to this greater volatility. In addition, FPL's shift to stochastic LOLP modeling provides a look at a variety of different weather scenarios that affect FPL's demand throughout the year.

II.H. DSM

In this Site Plan, FPL accounts for the effects of its DSM energy efficiency programs through August 2025, which are embedded in the actual usage data for forecasting purposes. In addition, FPL accounts for the following projected DSM MW and MWh impacts as "line item reductions" to the

forecasts as part of the IRP process: 1) the impacts of incremental energy efficiency that have been implemented after the 2025 Summer peaks have occurred, 2) projected impacts from incremental energy efficiency and load management, and 3) the impacts from previous signups in FPL's load management programs that will continue through 2035. After making these line-item adjustments to the load forecasted load values, the resulting "firm" load forecast, as shown in Chapter III in Schedules 7.1 and 7.2, is then used in the IRP work.

Historical and Forecast Load Information – Schedules 2-4

Schedules 2 through 4 below provide information regarding FPL's historical and forecasted load. Note that all historical information combines the load information of FPL and FPL NWFL.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2016	10,937,941	2.34	64,027	4,680,566	13,679	51,225	596,232	85,915
2017	11,075,378	2.34	63,373	4,740,017	13,370	50,951	604,336	84,309
2018	11,171,510	2.33	64,643	4,798,780	13,471	51,238	610,454	83,935
2019	11,256,787	2.30	65,872	4,886,791	13,480	51,857	622,212	83,344
2020	11,332,537	2.28	69,197	4,960,827	13,949	49,685	628,861	79,007
2021	11,441,385	2.27	67,162	5,036,950	13,334	50,506	636,044	79,407
2022	11,630,105	2.27	69,348	5,113,458	13,562	51,851	641,605	80,814
2023	11,827,634	2.28	70,206	5,179,816	13,554	52,507	642,772	81,689
2024	11,990,462	2.27	70,894	5,287,101	13,409	53,138	650,176	81,729
2025	12,323,105	2.29	70,912	5,379,448	13,182	53,481	658,442	81,224

Historical Values (2016 - 2025):

Col. (2) represents population in the area served by the consolidated system.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2026	12,364,033	2.26	71,769	5,461,802	13,140	53,743	667,102	80,561
2027	12,415,987	2.24	72,468	5,536,552	13,089	53,769	674,106	79,763
2028	12,479,732	2.23	73,630	5,606,956	13,132	54,049	680,348	79,443
2029	12,561,852	2.21	74,811	5,675,757	13,181	54,337	686,013	79,207
2030	12,662,585	2.20	76,052	5,743,740	13,241	54,538	691,990	78,813
2031	12,767,864	2.20	77,547	5,809,628	13,348	54,731	698,254	78,383
2032	12,874,160	2.19	79,124	5,874,123	13,470	54,926	704,250	77,992
2033	12,980,871	2.19	80,605	5,937,953	13,575	55,064	709,983	77,557
2034	13,087,064	2.18	82,145	6,002,273	13,686	55,154	715,653	77,069
2035	13,194,706	2.17	83,896	6,068,401	13,825	55,251	721,256	76,604

Projected Values (2026 - 2035):

Col. (2) represents population in the area served by the consolidated system.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial		Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2016	4,892	12,012	407,231	92	472	23	120,730
2017	4,693	11,904	394,249	83	473	41	119,614
2018	4,770	11,850	402,549	80	473	23	121,227
2019	4,759	12,043	395,169	82	456	23	123,050
2020	4,749	12,239	388,022	71	445	20	124,166
2021	4,721	12,785	369,236	68	433	19	122,908
2022	4,714	14,094	334,458	71	427	39	126,450
2023	4,617	15,625	295,521	67	420	86	127,904
2024	4,841	15,160	319,325	67	417	29	129,386
2025	4,574	13,929	328,401	63	416	24	129,471

Historical Values (2016 - 2025):

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) represents actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial		Railroads &	Street & Highway	Sales to Public	Sales to Ultimate
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	Railways GWh	Lighting GWh	Authorities GWh	Consumers GWh
2026	4,597	14,589	315,104	70	424	23	130,625
2027	4,602	14,716	312,757	70	420	23	131,352
2028	6,132	14,866	412,472	70	424	23	134,327
2029	8,933	15,033	594,191	70	435	23	138,608
2030	11,733	15,168	773,557	70	439	23	142,854
2031	14,532	15,236	953,755	70	452	23	147,354
2032	17,359	15,215	1,140,917	70	452	23	151,954
2033	20,120	15,096	1,332,795	70	452	23	156,334
2034	22,911	14,896	1,538,040	70	452	23	160,754
2035	25,701	14,718	1,746,299	70	452	23	165,393

Projected Values (2026 - 2035):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy For Load GWh	Average No. of Other Customers	Total Average Number of Customers
2016	6,937	5,981	133,649	4,603	5,293,413
2017	6,711	6,136	132,460	4,674	5,360,931
2018	7,089	6,188	134,504	4,923	5,426,008
2019	7,616	6,499	137,165	5,357	5,526,403
2020	8,503	6,514	139,183	5,743	5,607,670
2021	7,060	6,800	136,768	6,153	5,691,932
2022	8,476	5,990	140,916	6,687	5,775,844
2023	8,167	7,684	143,756	6,947	5,845,160
2024	8,923	7,794	146,103	7,314	5,959,750
2025	9,160	8,640	147,271	7,814	6,059,632

Historical Values (2016 - 2025):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy For Load GWh	Average No. of Other Customers	Total Average Number of Customers
2026	8,861	7,013	146,498	8,335	6,151,827
2027	8,863	7,468	147,683	8,923	6,234,296
2028	9,353	7,555	151,235	9,606	6,311,776
2029	9,529	7,635	155,772	10,398	6,387,202
2030	9,363	7,694	159,911	11,324	6,462,222
2031	9,009	7,775	164,138	12,395	6,535,513
2032	9,039	7,866	168,858	12,938	6,606,527
2033	9,059	7,945	173,338	12,938	6,675,970
2034	8,724	8,014	177,492	12,937	6,745,759
2035	7,242	8,042	180,678	12,936	6,817,311

Projected Values (2026 - 2035):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18).

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8) + Schedule 2.2 Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2016	26,044	1,443	24,601	0	882	1,809	836	1,119	24,326
2017	25,662	1,467	24,194	0	910	1,826	825	1,135	23,927
2018	25,411	1,418	23,993	0	866	1,839	866	1,149	23,679
2019	26,594	1,367	25,227	0	852	1,850	879	1,159	24,863
2020	26,400	1,595	24,805	0	845	1,861	887	1,175	24,668
2021	26,248	1,401	24,847	0	830	1,874	882	1,190	24,536
2022	26,429	1,572	24,857	0	827	1,886	871	1,201	24,731
2023	28,461	1,652	26,808	0	797	1,900	946	1,210	26,718
2024	28,266	1,731	26,535	0	863	1,917	961	1,221	26,442
2025	28,773	1,789	26,983	0	908	1,935	960	1,239	26,905

Historical Values (2016 - 2025):

Col. (2) and Col. (3) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2026	28,868	1,800	27,068	0	978	22	899	11	26,958
2027	29,259	1,796	27,463	0	951	42	905	18	27,343
2028	30,033	1,995	28,038	0	935	61	910	26	28,101
2029	30,682	1,894	28,788	0	923	80	914	33	28,732
2030	31,325	1,785	29,539	0	916	99	918	41	29,352
2031	32,175	1,712	30,463	0	913	118	922	48	30,174
2032	33,115	1,717	31,397	0	909	136	925	56	31,087
2033	34,038	1,722	32,315	0	907	154	929	64	31,983
2034	34,874	1,628	33,246	0	905	173	933	72	32,791
2035	35,623	1,418	34,205	0	903	191	933	81	33,515

Projected Values (2026 - 2035):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.2
History of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2016	18,826	1,167	17,659	0	742	1,232	570	528	17,514
2017	19,320	1,187	18,133	0	759	1,238	577	541	17,984
2018	21,533	1,332	20,201	0	750	1,244	588	547	20,194
2019	17,941	1,498	16,442	0	706	1,248	613	557	16,621
2020	19,569	1,312	18,257	0	702	1,253	614	568	18,253
2021	17,486	1,344	16,142	0	689	1,256	619	580	16,178
2022	21,027	1,230	19,797	0	681	1,258	628	584	19,718
2023	19,271	1,214	18,057	0	670	1,263	631	589	17,970
2024	18,595	1,093	17,502	0	743	1,272	657	597	17,195
2025	21,502	1,640	19,862	0	757	1,285	682	607	20,064

Historical Values (2016 - 2025):

Col. (2) and Col. (3) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2026	23,478	1,581	21,897	0	753	12	699	6	22,007
2027	23,962	1,733	22,228	0	732	25	705	11	22,489
2028	24,515	1,924	22,591	0	718	37	710	16	23,033
2029	25,070	1,843	23,227	0	710	50	714	21	23,575
2030	25,405	1,529	23,875	0	703	62	718	26	23,895
2031	26,018	1,454	24,564	0	702	74	722	32	24,488
2032	26,716	1,459	25,257	0	701	87	726	37	25,165
2033	27,404	1,463	25,941	0	701	99	730	42	25,832
2034	28,000	1,367	26,633	0	701	111	733	48	26,407
2035	28,499	1,156	27,343	0	702	124	737	53	26,884

Projected Values (2026 - 2035):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Actual Net Energy For Load GWh	Sales for Resale GWh	Utility Use & Losses GWh	Actual Total Retail Sales (GWh)	Load Factor(%)
2016	140,578	3,891	3,038	133,649	6,937	5,981	120,730	58.4%
2017	139,467	3,920	3,088	132,460	6,711	6,136	119,614	58.9%
2018	141,604	3,947	3,153	134,504	7,089	6,188	121,227	60.4%
2019	144,323	3,972	3,186	137,165	7,616	6,499	123,050	58.9%
2020	146,397	3,995	3,219	139,183	8,503	6,514	124,166	60.0%
2021	144,025	4,021	3,236	136,768	7,060	6,800	122,908	59.5%
2022	148,226	4,057	3,253	140,916	8,476	5,990	126,450	60.9%
2023	151,150	4,091	3,303	143,756	8,167	7,684	127,904	57.7%
2024	153,582	4,140	3,339	146,103	8,923	7,794	129,386	58.8%
2025	154,852	4,192	3,389	147,271	9,160	8,640	129,471	58.4%

Historical Values (2016 - 2025):

Col. (2) represents derived NEL not including conservation using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are annual (12-month) DSM values and represent total GWh reductions experienced each year.

Col. (8) is the Total Retail Sales calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and the greater of Col. (2) from Schedules 3.1 and 3.2 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Forecasted Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Net Energy For Load Adjusted for DSM GWh	Sales for Resale GWh	Utility Use & Losses GWh	Forecasted Total Billed Retail Energy Sales w/o DSM GWh	Load Factor(%)
2026	146,498	53	46	146,400	8,861	7,013	130,625	57.9%
2027	147,683	106	95	147,482	8,863	7,468	131,352	57.5%
2028	151,235	158	146	150,932	9,353	7,555	134,327	57.2%
2029	155,772	209	197	155,366	9,529	7,635	138,608	57.8%
2030	159,911	261	248	159,402	9,363	7,694	142,854	58.1%
2031	164,138	313	301	163,524	9,009	7,775	147,354	58.0%
2032	168,858	364	354	168,140	9,039	7,866	151,954	57.8%
2033	173,338	415	409	172,514	9,059	7,945	156,334	57.9%
2034	177,492	466	463	176,562	8,724	8,014	160,754	57.8%
2035	180,678	517	518	179,642	7,242	8,042	165,393	57.6%

Projected Values (2026 - 2035):

Col. (2) represents Forecasted NEL and does not include incremental conservation. It is the summation of Cols. (3) through (5).

Col. (3) & Col. (4) are forecasted values representing reduction on sales from incremental conservation.

Col. (5) is forecasted NEL and includes incremental conservation as well company use and losses.

Col. (8) is Total Retail Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (10) from Schedule 3.1 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Total Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2025 ACTUAL		2026 FORECAST		2027 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	21,502	10,673	23,478	10,722	23,962	10,804
FEB	20,522	9,686	21,875	9,852	22,194	9,945
MAR	22,284	10,429	21,870	10,685	22,182	10,771
APR	22,570	11,550	23,423	11,252	23,756	11,351
MAY	26,457	13,894	25,723	12,978	26,073	12,990
JUN	26,140	14,018	27,718	13,632	28,096	13,765
JUL	28,773	15,113	28,237	14,671	28,623	14,778
AUG	28,735	15,197	28,868	14,869	29,259	14,966
SEP	26,187	13,289	27,720	13,596	28,096	13,769
OCT	24,161	12,599	25,886	12,656	26,239	12,773
NOV	21,556	10,265	22,605	10,745	22,914	10,818
DEC	19,272	10,560	21,366	10,839	21,662	10,953
Annual Values:		**147,271**		**146,498**		**147,683**

Col. (3) annual value shown is consistent with the value shown in Col.(5) of Schedule 3.3.

Cols. (4) through (7) do not include the impacts of cumulative load management, incremental utility conservation, or incremental load management.

(This page is intentionally left blank.)

CHAPTER III

Projection of Incremental Resource Additions

(This page is intentionally left blank.)

III. Projection of Incremental Resource Additions

III.A. FPL's Resource Planning:

FPL utilizes its well-established and continually evolving integrated resource planning (IRP) process, in whole or in part as dictated by analysis needs, to determine: (i) the magnitude and timing of needed resources, and (ii) the type of resources that should be added. This section describes FPL's basic IRP process which was used during 2025 and early 2026 to develop the resource plans for FPL's system that are presented in this 2026 Site Plan. It also discusses some of the key assumptions, in addition to a new load forecast discussed in the previous chapter, which were used in developing this resource plan.

Four Fundamental Steps of FPL's Resource Planning:

The four fundamental steps of FPL's resource planning process are:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of projected resource needs (*e.g.*, identify competing options and resource plans);

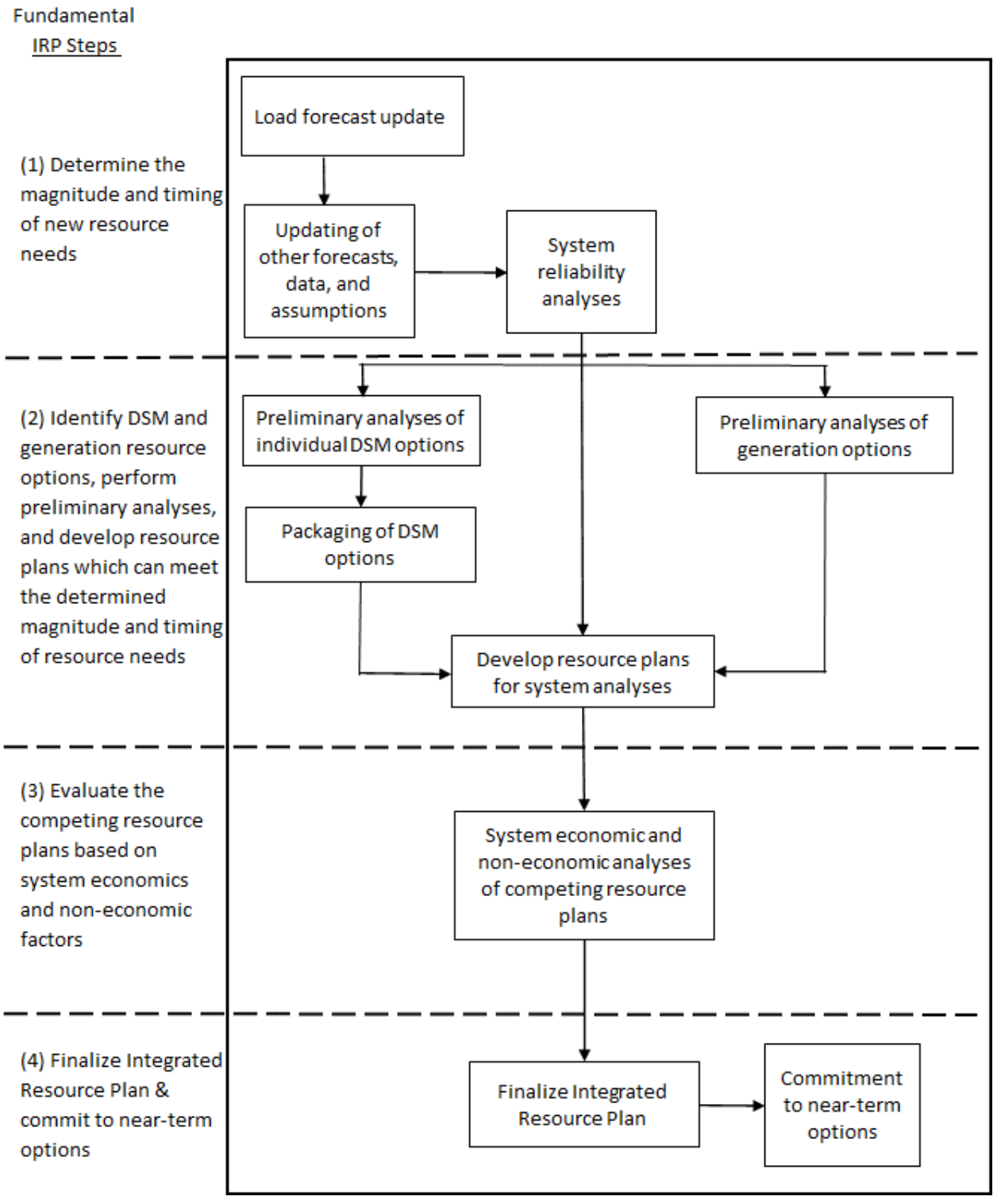
Step 3: Evaluate the competing options and resource plans based on system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of IRP Process: Fundamental Steps

Figure III.A.1: Overview of IRP Process



Step 1: Determine the Magnitude and Timing of New Resource Needs:

The first of the four resource planning steps is essentially a determination of the amount and timing of MW load reduction, new capacity additions, or a combination of both, which are needed to maintain and/or enhance system reliability. This step is often referred to as a reliability assessment for the utility system.

This analysis typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used throughout other aspects of FPL's resource planning process. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, current power plant capability and operating assumptions, costs of new resource additions, and current DSM demand and energy reduction assumptions.

FPL's process also includes key sets of projections regarding three specific types of resources: (1) generating unit capacity changes, (2) firm capacity PPAs, and (3) DSM implementation.

Key Assumptions Regarding the Three Types of Resources:

Generating Unit Capacity Additions:

The first set of assumptions, generating unit capacity changes, is based on current projections of new generating capacity additions and planned retirements of existing generating units. In this 2026 Site Plan, there are four types of projected generation capacity changes through the ten-year reporting time frame of this document. These changes are listed below in general chronological order:

1. Additional Solar Energy Facilities:

In this 2026 Site Plan, the resource plan projects the addition of approximately 12,293 MW of new solar generation during the 2026-2035 period. These additions are projected to be sited throughout FPL's service area. These projected solar additions for 2026-2035, when combined with solar additions made prior to 2026, will result in a total of approximately 20,225 MW of total installed utility solar by the end of 2035.

All solar projected to be added from 2026-2035 is "tracking" solar. In fixed-tilt solar configurations, the solar panels remain facing the same angle, while tracking solar changes the angle of the solar panels to follow the path of the sun during the day, generally resulting

in greater annual energy production, which allows for a greater customer benefit from fuel savings and production tax credits.

2. Additional Battery Storage:

At the end of 2021, a battery storage facility with a projected maximum output of 409 MW was placed in service at the existing Manatee plant site. This large battery storage facility is charged by solar energy from an existing nearby solar facility. Two 30 MW battery storage facilities were installed at two different locations in the FPL service area and put into service at the end of 2021. Both 30 MW battery storage facilities are also charged by existing solar facilities. In late 2025, seven 74.5 MW battery storage facilities were installed across the NWFL service area, totaling 521.5 MW of additional reliable capacity. Each facility is co-located with an existing solar site and charged directly by that site's solar generation. In addition, the resource plan presented in this Site Plan projects that an additional 7,454 MW of battery storage facilities will be installed by 2035 throughout FPL's service area.

3. Retirement of Existing Generating Units:

The resource plan for the 2026 TYSP reflects the retirements of two units: Gulf Clean Energy Center Units 4 & 5. These units will be retired at the end of 2029.

4. Enhancements of Existing Generating Units:

In previous Site Plans, FPL discussed plans to upgrade the CT components in several of FPL's existing CC units. That upgrade effort is still included in the resource plan presented in this Site Plan. These additional upgrades are projected to be completed by 2028. Information regarding the specific units, timing, and magnitude of these upgrades is presented in Schedule 8 in this chapter.

In addition, FPL implemented a pilot project that results in hydrogen replacing a portion of the natural gas that is currently being used to fuel the existing Okeechobee CC unit. In this pilot project, hydrogen is created by using solar energy, or other energy from the electric grid, to power an electrolyzer that separates water into hydrogen and oxygen (If the hydrogen is created using only solar or other renewable energy sources, the hydrogen is referred to as "green" hydrogen). The resulting hydrogen is then stored in on-site tanks until it is used as a fuel. The objective of the pilot project is to test, in practice, the concept of blending natural gas with hydrogen as a fuel for CC unit use. This pilot project went into service in late 2023.

Firm Capacity PPAs:

The second set of assumptions involves other firm capacity PPAs. These assumptions are generally consistent with those presented in FPL's 2025 Site Plan.

The remaining projected firm capacity purchases are from independent power producers. Details for these other purchases, including the annual total capacity values, are presented in Chapter I in Tables I.A.3.2 and I.A.3.3. These purchased firm capacity amounts were incorporated in the resource planning work that led to the resource plan presented in this document.

DSM Implementation:

The third set of assumptions involves a projection of the amount of incremental DSM that FPL anticipates implementing annually over the ten-year reporting period of 2026-2035 for this Site Plan. In April of 2024, FPL filed its proposed 2024 DSM Goals. These Goals were approved by the FPSC, and FPL filed a plan to meet these goals in March 2025, which was approved with modifications by the FPSC. This approved plan accounts for the projected annual amounts of Summer MW reduction, Winter MW reduction, and energy (MWh) reduction for the years 2026-2035.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

FPL's resource planning process applies these key assumptions, plus the other updated information described above, in the first fundamental step: determining the magnitude and timing of future resource needs. This determination is accomplished through system reliability analyses. Until 2014, FPL's reliability analyses were based on dual planning criteria, including a minimum peak-period total reserve margin (TRM) of 20% (FPL applies this criterion to both Summer and Winter peaks) and a maximum LOLP of 0.1 day per year. Both criteria are commonly used throughout the utility industry. Beginning in 2014, FPL began utilizing a third reliability criterion: a 10% GRM.

These reliability criteria utilize two basic types of methodologies: deterministic and probabilistic. The calculation of excess firm capacity at the annual system peaks (reserve margin) is a common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements, such as the impact of individual unit failures. For example, two 50 MW units that can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit that also can be counted on to run 90% of the time. Probabilistic methods

can also account for the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system and are used to perform system reliability analyses. Among the most widely used is LOLP, which FPL's resource planning group utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (*i.e.*, a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the system firm load could not be met. The standard for LOLP used by FPL's resource planning group is a maximum of 0.1 day per year which is commonly accepted throughout the industry. This analysis requires a more complicated calculation methodology than the reserve margin analysis. LOLP analyses are typically carried out using computer software models, such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

Recently, FPL has expanded usage of its LOLP criterion by utilizing a stochastic approach to LOLP modeling. As FPL's system continues to incorporate additional cost-effective intermittent solar generation, the Company is continuing to adapt its resource planning to ensure that customers' reliability needs are met through available, dispatchable resources that provide value to customers. Just as FPL's system has advanced and modernized over time, resource adequacy must also be modernized to consider evolving conditions that affect the delivery of power in times of greatest need. To that end, FPL retained an independent third-party consulting firm, E3 Consulting, to perform a comprehensive, stochastic LOLP analysis in 2025 to ensure that FPL's proposed system additions optimally address system needs for each hour of the year.

FPL's incorporation of cost-effective solar has increased to the extent that the peak hour of the year – *i.e.*, the hour of greatest demand on the system – is no longer the most critical hour for determining reliability need. Now, the most critical time for capacity on FPL's system is at peak net

demand, which most often occurs between 5:00 p.m. and 8:00 p.m., when solar facilities are providing less generation output. For these hours, as well as all other hours throughout the year, FPL needs additional, more modernized modeling analysis to determine its resource adequacy and identify where its greatest resource needs lie. Thus, for its recent resource planning, FPL added a stochastic LOLP analysis tailored to its system to identify (1) hourly periods of the year where there is increased likelihood for a loss of load, and (2) available resources that can remediate the potential for that loss.

Stochastic LOLP modeling incorporates vast amounts of data to develop a granular view of a utility's system adequacy in hour-by-hour segments. This modeling incorporates significantly more data in assessing system reliability than a traditional LOLP analysis, providing a substantially wider range of load and generation conditions across numerous scenarios. Through this analysis, a utility can more effectively determine the sufficiency of its hourly generation supply throughout the year, which, in turn, allows it to identify any needed system additions.

The stochastic LOLP analysis incorporates a tremendous amount of system-specific data required to develop a probabilistic hourly load and supply projection and identify the system's reliability needs. In comparison, a traditional reserve margin analysis provides a more limited and simplified look at system operations, examining only the peak demand hour at two times of the year – once in the winter and once in the summer – without considering the unique generation attributes of the utility's fleet. The traditional reserve margin analysis therefore carries analytical shortcomings, particularly for systems that incorporate substantial renewable generation. For example, as FPL's solar generation portfolio has increased, the hours of the day with the least reserves are more likely to be found in the evening as the sun begins to set and solar generation decreases. The traditional reserve margin analysis does not fully reflect this more recent trend. The traditional reserve margin analysis also fails to capture the interactive effects of non-dispatchable generation and load, which have become increasingly challenging to predict and model. The stochastic LOLP analysis addresses these shortcomings by accounting for and modeling these factors, assessing resource availability at every hour of the year and identifying the periods when reserves are most depleted, wherever they may fall.

The stochastic modeling also presents a more sophisticated analysis than FPL's prior LOLP analyses. A traditional LOLP analysis models expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages. The stochastic LOLP analysis, however, simulates a random selection of plant outages, which better reflects the unpredictable nature of unavailable generation as observed in normal system

operations. Additionally, a traditional LOLP analysis models an expected solar generation profile, whereas the stochastic LOLP analysis produces a reliability assessment that captures the natural variability in solar production due to weather conditions. The stochastic LOLP model also better captures the synergistic interactions between load and non-dispatchable generation because it models the variability of each input separately.

In 2025, the consulting firm E3 coordinated with FPL and used hourly temperature data from representative weather stations to develop hourly load profiles using a machine learning algorithm trained on actual load and temperatures from 2003 to 2023. E3 also used historic satellite data to simulate hourly solar generation at each of the current and future solar generating sites for the 1980 to 2023 period, as well as actual historical generating unit availability data to calculate an expected forced outage rate and a mean time to repair for every generating unit in the FPL fleet. The model used these inputs to randomly select which units may experience an outage at any given time within the simulations. FPL has incorporated the results of this study to produce the resource plan in this Site Plan and will continue to examine stochastic LOLP studies to accentuate future resource planning efforts.

FPL's third reliability criterion, the 10% minimum Summer and Winter GRM criterion, augments the other two reliability criteria by providing an indication of the respective roles that DSM and generation are projected to play each year as FPL maintains its 20% Summer and Winter TRMs (which account for both generation and DSM resources). All three reliability criteria are useful to identify the timing and magnitude of the resource needs because of the different perspectives the three criteria provide. In addition, the GRM criterion is particularly useful in providing direction regarding the mix of generation (solar, battery storage, etc.) and DSM resources that should be added to maintain and enhance system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of Projected Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in certain key characteristics may be conducted to determine what type of new capacity option appears to be the most competitive on FPL's system. Preliminary analyses also can help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or

evaluation of existing DSM options are often conducted in this second fundamental IRP step when FPL is determining its DSM goals.

FPL's resource planning group typically utilizes an optimization model to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM Conservation, Planning, and Forecasting (CPF) model, which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL typically uses two additional models. One is a proprietary non-linear programming (NLP) model that is used to analyze the potential for lowering system peak loads through additional load management/demand response capability. The other model that is utilized is a proprietary linear programming (LP) model with which DSM portfolios are developed.

The next step is typically to "package" the individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses into different resource plans that are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, different combinations of new resource options (*i.e.*, resource plans) of a magnitude and timing necessary to meet the projected resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans Based on System Economics and Non-Economic Factors:

At the completion of fundamental Steps 1 and 2, the most viable new resource options have been identified, and these resource options have been combined into resource plans that each meet the magnitude and timing of projected resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all the impacts to the utility system from the competing resource options/resource plans. FPL's resource planning group typically utilizes the AURORA optimization model to develop and perform the system

economic analyses of resource plans. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on electricity rate levels, with the general objective of minimizing the projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of the impacts of competing resource plans on both electricity rates and system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

FPL's resource planning group also includes other factors in its evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative but non-economic terms, such as percentages, tons, etc., rather than in terms of dollars. These factors are often referred to as "system concerns or factors," which include reducing emissions, maintaining/enhancing fuel diversity, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern region of FPL's area that consists of Miami-Dade and Broward counties. In conducting the evaluations needed to determine which resource options and resource plans are best for the utility system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These and other factors are discussed later in this chapter in section III.C.

Step 4: Finalizing the Current Resource Plan

The results of the previous three fundamental steps are typically used to develop a new or updated resource plan. The current resource plan presented in this 2026 Site Plan is summarized in the following section.

III.B. Projected Incremental Resource Changes in the Resource Plan

The projection of major changes in the resource plan, including both utility-owned generation and PPAs, for the years 2026-2035 is summarized in Table ES-1 in the Executive Summary. In regard to DSM additions, all of the DSM presented in this Site Plan represents FPL's DSM through the end of 2035. Those annual amounts are shown in Schedules 3.1, 3.2, and 3.3 in Chapter II.

A summary of some of the larger resource additions/retirements include those listed below:

- New solar (PV) additions from 2026 through 2035 of approximately 12,293 MW (nameplate);
- A total addition of approximately 7,454 MW of battery storage through 2035;
- Incorporation of the 672 MW Vandolah plant in 2027;
- Capacity upgrades at several of FPL's existing CC units through 2028;
- The retirement of Gulf Coast Clean Energy Center Units 4 and 5 at the end of 2029; and
- Total additions of 3,276 MW of CT capacity from 2032 through 2035.

With the exception of certain resource additions and retirements listed above in the earlier years of the 2026-2035 time period addressed in this 2026 Site Plan, FPL notes that final decisions on other resource options shown in this Site Plan are not needed at this time, nor have they been made. This is particularly relevant to resource additions shown for years increasingly further out in the ten-year reporting period. Consequently, those resource additions are more prone to future change.

III.C Discussion of the Resource Plan and Issues Impacting Resource Planning Work

In considering the resource plans presented in this Site Plan, it is useful to note that there are at least eleven significant factors that either influenced the current resource plan or which may result in future changes. These factors are discussed below (in no particular order).

1. **Impacts of the Tax Credits for Batteries and Solar:**
   FPL's resource planning work continues to factor in tax credits for new utility-owned batteries and solar, as well as recent changes in the long-term deployment of these credits. For new utility-owned standalone batteries, the 30% ITC effectively lowers the capital cost for a new battery, with the potential of an additional 10% if the battery is located in a specific area. For new utility-owned solar, a utility can elect a PTC for new solar that is based on the amount of

energy (MWh) the new solar facility generates each year for the first ten years of operation. For future resource additions, the PTC rate in 2026 starts at $31 for each MWh generated.[4] The $31 per MWh credit amount for a new solar facility that comes in-service increases with inflation each year. In mid-2025, the OBBBA was signed and changed the projection of future ITCs and PTCs. With this new bill enacted, all of FPL's projected solar additions through 2026 will qualify for 100% of the PTC. FPL's projected solar additions through 2030 will also still be eligible for the full PTC, as all of those sites come within the "Safe Harbor" guidelines that require construction to commence on or before one year of the enactment of the OBBBA. The additional solar units that are presented in this Site Plan through the remainder of the ten-year period will not be eligible for the PTC. The battery storage ITC has also been affected by the OBBBA, but the associated impacts occur on a different timeline. In terms of the resource additions in this Site Plan, all planned battery storage will still be eligible for the 30% ITC through 2035. FPL's resource plan presented in this Site Plan accounts for the effects of these tax credits and the impact of the OBBBA.

2. **The critical need to maintain a balance between load and generating capacity in specific regions of FPL's service area, such as in Northwest Florida and Southeastern Florida (Miami-Dade and Broward counties):**

   This balance has both reliability and economic implications for FPL's system and customers, and it is a key reason that FPL has expanded generation and transmission in specific areas in the past.

3. **The desire to maintain/enhance fuel diversity in the FPL system while considering system economics and reliability:**

   In 2025, FPL used natural gas to generate approximately 68% of the total electricity it delivered to its customers. By 2035, due largely to significant solar additions, the percentage of electricity generated by natural gas for FPL's system is projected to decrease to approximately 57% based on the resource plan presented in this Site Plan. Due to this reliance on natural gas, opportunities to economically maintain and enhance fuel diversity are continually sought, with due consideration given to system economics. For example, FPL is projecting the addition of cost-effective solar generation throughout the ten-year reporting period of this document.

[4] To illustrate the magnitude of the impact of the solar PTC, take a simple example of a 74.5 MW solar facility that produces approximately 150,000 MWh per year in 2026 (*i.e.*, assuming a net capacity factor of 23%). The proposed solar PTC for that year would result in a tax credit of (150,000 MWh x $31/MWh =) $4.7 million. This first year tax credit would then be extended for nine more years while being adjusted for inflation.

These solar additions enhance fuel diversity while at the same time allowing for the lowest cost generation resource to be constructed and operated. To enhance the reliability of these solar additions, FPL is planning to add cost-effective battery storage to ensure adequate generation and reserves at the time of the net system peak (FPL's peak after accounting for solar generation).

In the past, coal-fired units have been examined as an option to increase system fuel diversity. However, coal units have ceased to be viable generation options for a number of reasons which include: (i) increased economic competitiveness of solar and battery storage, (ii) much lower forecasted costs for natural gas, (iii) increased availability of natural gas, and (iv) environmental regulations regarding coal units. Consequently, FPL does not believe that new advanced technology coal units are viable fuel diversity enhancement options in Florida.

Therefore, FPL has focused on: (i) cost-effectively adding solar energy and battery storage to enhance fuel diversity and independence, (ii) diversifying the sources of natural gas, (iii) diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, (iv) using natural gas more efficiently, and (v) expanding the ability of its units to burn liquid fuel as a backup to natural gas. FPL has also launched a pilot project that tests the concept of using green hydrogen as a substitute for some of the natural gas now being used to fuel one of its existing CC units.

Solar Energy: The resource plan in this 2026 Site Plan projects that FPL will have a total of approximately 20,225 MW of solar generation by the end of 2035. Such a level of solar nameplate capacity would represent about 55% of FPL's current total installed capacity (MW). However, the impact of solar contribution in terms of actual energy produced (MWh) is smaller. Because solar energy can only be generated during daylight hours and is impacted by factors such as clouds and rain, solar has a capacity factor of approximately 23% to 30% in the state of Florida. As a result, FPL's solar additions would be projected to supply approximately 26% of the total energy (MWh) delivered in 2035 (as shown in Schedule 6.2 later in this chapter).[7]

Based on the resource plan presented in this 2026 Site Plan, it is projected that by 2035 approximately 26% of all energy produced on FPL's system will be from solar. This percentage of energy that is projected to be delivered by solar energy is significant for a utility system of FPL's size, especially when considering that the total amount of energy projected to be delivered to customers in 2035 will have also increased by approximately 23%. The projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 later in this chapter.

Nuclear Energy: In 2008, the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized the company to recover project-related expenditures that were approved as a result of annual nuclear cost recovery filings. FPL successfully completed this nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity was delivered by the project, which represents an increase of approximately 30% more incremental capacity than was originally forecasted when the project began. Additional uprates followed which resulted in approximately 40 MW more capacity. FPL's customers are currently benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

In June 2009, FPL began the process of securing COLs from the federal NRC for two future nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (the location of two existing nuclear generating units). In April 2018, FPL received NRC approval for these two COLs, and these licenses currently remain valid.

FPL has paused the decision whether to seek FPSC approval to move forward with construction of Turkey Point Units 6 & 7. FPL intends to incorporate into any decision regarding Turkey Point Units 6 & 7 the experience gained from the construction and operation of Georgia Power's Vogtle nuclear units. As a result, the earliest possible in-service dates for Turkey Point 6 & 7 are beyond the ten-year period addressed in this 2026 Site Plan. This Site Plan continues to present the Turkey Point location as a Preferred Site for nuclear generation as indicated in Chapter IV.

On January 30, 2018, FPL applied to the NRC for SLR for FPL's existing Turkey Point Units 3 & 4. The previous license terms for these two existing nuclear units extended into the years 2032 and 2033, respectively. The SLR requested approval to extend the operating licenses by 20 years to 2052 and 2053, respectively. The NRC granted approval for the SLR in December 2019. On February 24, 2022, the NRC on its own accord reversed its adjudicatory decision interpreting environmental rules related to SLRs. In particular, the NRC concluded that its environmental review of all pending SLR requests under the National Environmental Policy Act was insufficient due to inadequacies of the NRC's Generic Environmental Impact Statement (GEIS) for license renewal, which is applicable to all plants. With this action, the NRC directed its staff to amend the Turkey Point Units 3 & 4 operating licenses by removing the 20-year term of licensed operation added by the SLR, thereby restoring the previous operating license expiration dates of 2032 and 2033 for Turkey Point Units 3 & 4, respectively.

Following this decision, SLR applicants had the option to satisfy the environmental review requirements either by requesting the NRC Staff to proceed with an entirely site-specific EIS or by waiting for the NRC to issue a revised GEIS that would address all SLR applications. In response to the NRC's action, FPL decided to pursue an entirely site-specific EIS for Turkey Point Units 3 & 4. The NRC completed its site-specific review of the application and reissued the 20-year SLR term for Turkey Point Units 3 and 4 on September 17, 2024. Certain intervenors sought hearing requests in the Turkey Point Units 3 & 4 subsequent license renewal proceeding. Following adjudicatory proceedings, no admitted contentions remained and the proceeding was terminated. Any further Commission-level review is subject to the NRC's established appellate processes.

For purposes of this Site Plan filing, FPL's resource planning analyses have assumed the continued operation of Turkey Point Units 3 & 4 through the currently pending new license termination dates of 2052 and 2053 for Units 3 & 4, respectively.

In the 3rd Quarter of 2021, FPL applied to the NRC for a SLR for its existing St. Lucie nuclear Units 1 & 2. If approved by the NRC, the SLRs for St. Lucie Units 1 & 2 will extend the licenses for those facilities for an additional 20 years until 2056 and 2063, respectively. The NRC schedule for the review of the St. Lucie SLR application has been delayed as the NRC worked to revise its generic EIS for license renewal in response to the Turkey Point SLR decision. FPL chose to wait for the completion of the NRC's revised GEIS and have the NRC incorporate that generic analysis into its St. Lucie review. The revised GEIS was published in August 2024. The current expectation is that the St. Lucie review, which incorporates the GEIS, will be completed in 2026. The revised GEIS is currently subject to a challenge in the Court of Appeals for the D.C. Circuit, but the NRC's review of the application remains ongoing. Similar to the assumption for the Turkey Point Units, FPL's resource planning analyses have assumed the continued operation of St. Lucie Units 1 & 2 through the new license termination dates of 2056 and 2063 for Units 1 & 2, respectively.

FPL is also continuing to monitor advanced nuclear power options such as SMRs. To prepare for the potential future commercial viability of SMRs, FPL plans to begin the initial stages of Early Site Permitting, available under NRC rules, in the 2026-2027 timeframe for a potential SMR at a site adjacent to an existing nuclear power plant. This strategic move is aimed at minimizing risks, allowing emerging technologies to mature, and enabling robust and well-developed regulatory frameworks prior to deployment, while remaining cognizant of the current high costs of nuclear and SMR development and taking a stepwise approach. FPL is closely

monitoring current initiatives at both the U.S. Department of Energy and the NRC. By taking these steps early on, FPL aims to be well-positioned to benefit from future nuclear deployment. The projected in-service date of an SMR would be outside the ten-year period addressed in this Site Plan.

Natural gas sourcing and delivery: FPL utilizes several natural gas pipelines to serve its existing natural gas units in Florida. These pipelines provide reliable, economic, and diverse natural gas supply to FPL and the State of Florida. In FPL NWFL, FPL's plants are served by Gulf South Pipeline Company, LP (Gulf South) and the Florida Gas Transmission Company, LLC (FGT). In peninsular Florida, FPL delivers gas using the FGT and the Gulfstream Natural Gas System (Gulfstream) pipelines along with the Sabal Trail Transmission and the Florida Southeast Connection pipelines which were placed in service in 2017.

Using natural gas more efficiently: FPL has sought ways to utilize natural gas more efficiently for years. Since 2008, FPL has modernized several of its existing plants sites from older, less efficient units into highly efficient CC units with much lower heat rates and higher capacities. These modernized units have improved the overall efficiency of FPL's system, allowing for higher output while using lower amounts of natural gas. This improved efficiency is graphically shown in Figure ES-2 in the Executive Summary.

Dual-fuel capability at existing units: Efforts are being made to maintain the ability to utilize ultra-low sulfur distillate (ULSD) oil at existing units that have that capability. Four new CTs were added at the Gulf Clean Energy Center in late 2021; these units have the capability to burn either natural gas or ULSD fuel oil. Having backup fuel capability ensures the ability of these units to provide generation even during potential disruptions of gas supply.

In the future, FPL's resource planning group will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity.

4. **The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations:**

As mentioned earlier in Section III.A, FPL utilizes a 10% GRM to ensure that system reliability is not negatively affected by an overreliance on non-generation resources, particularly at times of extreme load. This GRM reliability criterion was developed as a result of extensive analyses – which have been described in detail in prior FPL Site Plans – of FPL's system from both resource planning and system operations perspectives. The potential for overreliance upon

non-generating resources for system reliability remains an important resource planning issue and is one that will continue to be examined in ongoing resource planning work.

5. **The significant impact of federal and state energy efficiency codes and standards:**
As discussed in Chapter II, the load forecasts for FPL include projected impacts from federal and state energy efficiency codes and standards. These energy efficiency codes and standards are projected to have significant incremental impacts by reducing forecasted summer and winter peak loads, and by reducing annual NEL, in FPL's system. From the end of 2025 through the year 2035, these energy efficiency codes and standards are projected to reduce summer peak load by approximately 1,940 MW, reduce Winter peak load by approximately 420 MW, and reduce annual energy usage by approximately 2,600 GWh.

In addition to lowering the load forecast from what it otherwise would have been and thus serving to lower projected load and resource needs, this projected energy efficiency from the codes and standards also affects resource planning in another way: it lowers the potential market for utility DSM programs to cost-effectively deliver energy efficiency.

6. **The fuel cost and efficiency of FPL's fossil-fueled generation fleet and the avoidance of fuel costs through increased solar generation:**
There are two main factors that drive utility system costs for FPL's fossil-fueled generation fleet: (i) forecasted natural gas costs, and (ii) the efficiency with which generating units convert fuel into electricity. While natural gas costs always remain subject to supply, demand and geopolitical impacts, forecasted natural gas costs have recently been one of the lowest cost options for fuel, leading to low overall system fuel costs for FPL's customers when compared to other fuels like oil or coal. In addition to these natural gas costs, FPL customers also experience lower rates resulting from two other characteristics of FPL's system: 1) the amount of solar generation on FPL's system and 2) the efficiency of FPL's fossil-fueled generating units.

In 2025, FPL customers saved approximately $404 million in system fuel costs from FPL having solar generation on its system. Since 2017 (when FPL began scaling investment in cost-effective large-scale solar facilities), FPL has avoided approximately $1.5 billion of fuel costs because of its solar generation.

In regard to the fuel efficiency of FPL's fossil-fueled generating units, the amount of natural gas (BTU) needed to produce a kWh of electricity has declined from approximately 9,635 in 2001

to approximately 7,110 in 2025. This improvement of approximately 26% in fuel efficiency is truly significant, especially when considering the 20,000 MW-plus magnitude of gas-fueled generation on FPL's system. Overall, FPL's improvement in fuel efficiency has resulted in an estimated cumulative fuel cost savings for FPL's customers of approximately $16.1 billion from 2001 through 2025, including fuel cost savings of $860 million in 2025 alone.

7. Projected changes in CO_2 regulation and associated compliance costs:

Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has utilized projected compliance costs for CO_2 emissions prepared by an independent consultant, ICF, in its resource planning work. FPL continues to utilize ICF's forecast of projected CO_2 compliance costs in its resource planning process. The projected compliance costs in the current plan are the same as those used in the 2025 Ten Year Site Plan.

8. Projected increases in electric vehicle (EV) adoption:

FPL's current load forecast continues to project increasing levels of EV adoption throughout the ten-year period. The projected impacts of EVs on annual energy usage and peak loads are discussed in this document in Chapter II. Both the higher MWh and peak hour MW impacts of EVs will have resource planning implications.

9. Enhancing system reliability during extreme weather events:

Over the past several years, extreme weather events have caused significant outages and disruptions to electric grids across the country. These events include widespread hot weather in California in the summer of 2020, historic cold weather in Texas in February 2021, and extreme cold conditions throughout the Mid-Atlantic and Southeast around Christmas of 2022. FPL's NWFL area has continually set records in winter peak demand, including a record peak early in 2025 when widespread snowfall occurred throughout northern Florida. FPL's overall system has also hit all-time peaks for summer in 2025 and winter in early 2026. In addition to these peak events, FPL's service area regularly experiences periods of hotter than average weather throughout the year and hurricanes that can potentially affect the output of its generation fleet. While FPL does not plan its system around extreme events, it is prudent to consider and prepare for the possibility of extreme weather events and the ability to reliably serve customers under those circumstances. To that end, FPL has reviewed the lessons learned from the outages and service disruptions experienced in other jurisdictions and enhanced its own system so that it is adequately prepared. This includes winterizing FPL's nuclear and fossil-fueled generation units, enhancing cooperation and preparation between FPL and suppliers of natural gas and fuel oil, and keeping generation units as "extreme winter

only" units that will provide the lowest cost backup capacity in the event of extreme winter weather in FPL's service area. The additional dispatchable resources that FPL is adding throughout the ten-year period will also support reliability and grid stability throughout the year, including during extreme weather events.

FPL will continue to work with regulatory authorities, such as the FERC, the FPSC, and the NERC, to follow their guidance regarding proper planning procedures for extreme weather events.

10. Ensuring resource adequacy and system reliability throughout the entire year:

FPL's planning processes center around maintaining the reliability of its bulk electric system. For over the past two decades, the metric that drove most of FPL's reliability needs was its minimum 20% standard reserve margin, calculated at the time of summer and winter peak load. However, FPL's evolving system requires more in-depth reliability metrics to fully analyze resource adequacy across every hour of the year and through various potential scenarios, including variations in load, generating outages, and solar performance. Therefore, FPL has expanded use of its LOLP metric to include stochastic modeling that fully encompasses all of these scenarios, leading to a more robust evaluation of the reliability and resource adequacy of FPL's system. FPL's planned resources in this Site Plan address resource adequacy concerns by adding a variety of resources throughout the ten-year period that results in a robust, reliable, and cost-effective system to serve FPL's customers.

11. Future Impacts of Large Load customers:

Over the past several years, large load customers with high load factors have grown extensively throughout the U.S. These customers have expressed interest in establishing operations within Florida, which would greatly impact the demand and energy in FPL's future forecast. FPL's current load projections assume that demand from large load customers will materialize starting in 2028 and reach a peak demand of 3 GW by 2035. FPL's projections of demand and energy (and the associated resources needed to meet this demand) factor in this increase in load. FPL will continually examine the projected impacts of this demand on its future resource needs.

III.D Demand-Side Management (DSM)

FPL has sought and implemented cost-effective DSM programs since 1978. As such, cost-effective DSM has been a key focus of FPL's resource planning work for more than 40 years. During that time, FPL's DSM programs have included many energy efficiency and load management programs and initiatives.

There are several important factors affecting the feasibility and cost-effectiveness of utility DSM programs. The first factor is the growing impact of federal and state energy efficiency codes and standards. As discussed first in Chapters I and II, and earlier in Section III.C above, the projected incremental impacts of these energy efficiency codes and standards during the 2026-2035 time period has significantly lowered FPL's projected load and resource needs. In addition, these energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs.

Another factor placing downward pressure on the cost-effectiveness of utility DSM on the FPL system is the increasing efficiency with which FPL generates electricity. FPL's generating system has steadily become more efficient in its ability to generate electricity using less fossil fuel. For example, the FPL system is projected to use 27% less fossil fuel to generate a MWh in 2026 than it did in 2001. Again, this benefits FPL's customers by helping to significantly lower fuel costs and electric rates. However, the improvements in generating system efficiency affect DSM cost-effectiveness by lowering the system fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus lowering potential DSM benefits and DSM cost-effectiveness. As FPL adds more solar to its system, the overall efficiency of its system will continue to improve. Although the efficiency of FPL's system reduces possible benefits from DSM, FPL will continue to look for innovations and opportunities to cost-effectively empower customers and add system benefits through its DSM programs in the future.

In 2024, new DSM goals for the period 2025-2034 were approved in Docket No. 20240012-EG. FPL filed a DSM Plan to achieve these goals in March 2025, which the PSC approved with modifications. The DSM impacts contained in this Site Plan reflect the demand and energy impacts associated with the currently approved goals and the programs in the approved DSM Plan.

DSM Programs and Research & Development Efforts in FPL's 2025 DSM Plan

1. **Residential Home Energy Survey (HES)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The HES is also used to identify potential candidates for other FPL DSM programs.

2. **Residential Load Management (On Call)**

This program allows FPL to turn off certain customer-selected appliances using FPL-installed equipment during periods of extreme demand, capacity shortages, system emergencies, or for system frequency regulation. This program also includes a new HVAC on-bill option pilot.

3. **Residential Heating, Ventilating and Air Conditioning (HVAC)**

This program encourages customers to install high-efficiency central air-conditioning systems.

4. **Residential Ceiling Insulation**

This program encourages customers to improve their home's thermal efficiency.

5. **Residential New Construction (BuildSmart®)**

This program encourages builders and developers to design and construct new homes to achieve BuildSmart® certification and move towards ENERGY STAR® qualifications.

6. **Residential Low-Income Weatherization**

This program assists low-income customers through FPL-conducted Energy Retrofits and state Weatherization Assistance Provider (WAP) agencies.

7. **Residential Low-Income Renter Pilot**

This program encourages the adoption of high-efficiency HVAC equipment in low-income rental properties.

8. **Business Energy Evaluation (BEE)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM

programs. The BEE is also used to identify potential candidates for other FPL DSM programs.

9. **Commercial/Industrial Demand Reduction (CDR)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies.

10. **Commercial/Industrial Load Control (CILC)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. It was closed to new participants as of December 31, 2000.

11. **Business On-Call**

This program allows FPL to turn off customers' direct expansion central electric air conditioning units using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

12. **Business Heating, Ventilating and Air Conditioning (HVAC)**

This program encourages customers to install high-efficiency HVAC systems.

13. **Business Lighting**

This program encourages customers to install high-efficiency lighting systems.

14. **Business Custom Incentive (BCI)**

This program encourages customers to install unique high-efficiency technologies not covered by other FPL DSM programs.

15. **Conservation Research & Development (CRD) Project**

This project consists of industry research and studies designed to: identify new energy-efficient technologies; evaluate and quantify their impacts on energy, demand and customers; and where appropriate and cost-effective, incorporate an emerging technology into a DSM program.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV and above bulk transmission lines that must be certified under the Transmission Line Siting Act (TLSA). There are five such lines in the FPL system for this ten-year reporting period.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	Sweatt 1/	Whidden	79	June/2026	230	1,195
FPL	Oasis 2/	Andytown	30	December/2031	500	3,464
FPL	Oasis 2/	Quarry	15	December/2033	500	3,464
FPL	Quarry 2/	Oasis	15	December/2033	230	1,195
FPL	Levee 2/	Oasis	15	December/2033	230	1,195

1/ Need Determination for the Whidden to Sweatt project was approved on May 17, 2022, and Conditions of Certification were received in September 2022. The project is scheduled to be completed by June 2026.

2/ The Andytown-Oasis Transmission Lines Project consists of four related transmission lines. The determination of need was filed with the FPSC on March 11, 2026. The project has an overall planned in-service date of December 2033.

There will also be transmission facilities needed to connect several projected generation capacity additions to the FPL transmission system. These transmission facilities are described on the following pages. Sites for longer term additions, such as projected solar and BESS additions for 2028 and beyond, have not yet been definitively determined so no transmission analyses for these additions have been performed.

III.E.1 Transmission Facilities for the Clover Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Clover Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. **Substation:**

1. Construct a new 230 kV substation (Clover) on the project site.
2. Add one 230 kV line switch at Sunbreak for string bus to Clover substation (approximately 2.0 miles).
3. Add one 230kV breaker at Clover substation.
4. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
5. Construct 34.5 kV bus to connect the PV array to Clover 230 kV substation.
6. Add relays and other protective equipment.
7. Breaker replacements: None

II. **Transmission:**

1. Construct approximately 2.0 miles string bus from Sunbreak 230 kV to Clover substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.2 Transmission Facilities for the Sea Grape Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sea Grape Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Muscadine) on the project site, adjacent to the new Sunbreak - Morrow 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Muscadine substation.
3. Construct 34.5 kV bus to connect the PV array to Muscadine 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent Sunbreak - Morrow 230 kV into Muscadine substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.3 Transmission Facilities for the North Orange Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) North Orange Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. **Substation:**

1. Construct a new single bus, two (2) breaker 230 kV substation (Apricot) on the project site, adjacent to the new Sunbreak – Muscadine 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Apricot substation.
3. Construct 34.5 kV bus to connect the PV array to Apricot 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. **Transmission:**

1. Loop the adjacent Sunbreak - Muscadine 230 kV into Apricot substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.4 Transmission Facilities for the Sand Pine Solar Energy Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sand Pine Solar Energy Center in Calhoun County in the 2nd Quarter of 2026 is projected to be:

I. Substation:

1. Extend 230 kV bus at Quincy substation to a new substation (Chinkapin) and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Chinkapin 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None.

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.5 Transmission Facilities for the Big Brook Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Big Brook Battery Energy Storage System Center in Calhoun County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Song Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.6 Transmission Facilities for the Sand Pine Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sand Pine Battery Energy Storage System Center in Calhoun County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Quincy Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.7 Transmission Facilities for the North Orange Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) North Orange Battery Energy Storage System Center in St. Lucie County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Apricot Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.8 Transmission Facilities for the Norton Creek Battery Energy Storage System Center in Madison County

The work required to connect the approximate 74.5 MW (nameplate, AC) Norton Creek Battery Energy Storage System Center in Madison County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Bandit Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.9 Transmission Facilities for the Thomas Creek Battery Energy Storage System Center in Nassau County

The work required to connect the approximate 74.5 MW (nameplate, AC) Thomas Creek Battery Energy Storage System Center in Nassau County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Thomas Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.10 Transmission Facilities for the Cedar Trail Battery Energy Storage System Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Cedar Trail Battery Energy Storage System Center in Baker County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Deodar Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.11 Transmission Facilities for the Nature Trail Battery Energy Storage System Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Nature Trail Battery Energy Storage System Center in Baker County in the 3rd Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Harvey Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.12 Transmission Facilities for the Lansing Smith Battery Energy Storage System Center in Bay County

The work required to connect the approximate 400 MW (nameplate, AC) Lansing Smith Battery Energy Storage System Center in Bay County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new 230/34.5 kV substation (Parakeet) on the project site.
2. Add one 230 kV line terminal at Lansing Smith switchyard for string bus to Parakeet substation (approximately 0.26 miles).
3. Add two 230kV breakers at Lansing Smith switchyard.
4. Add two 230/34.5 kV main step-up transformer (225 MVA) with a 230 kV breaker at Parakeet substation to connect each BESS.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Construct approximately 0.26 miles string bus from Lansing Smith switchyard 230 kV to Parakeet substation.
2. No upgrades are expected to be necessary at this time.

III.E.13 Transmission Facilities for the Putnam Battery Energy Storage System Center in Putnam County

The work required to connect the approximate 200 MW (nameplate, AC) Putnam Battery Energy Storage System Center in Putnam County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new 230/34.5 kV substation (Putnam BESS U1) on the project site.
2. Add one 115 kV line terminal at Putnam switchyard for string bus to Putnam BESS U1 substation (approximately 0.3 miles).
3. Add two 115kV breakers at Putnam switchyard.
4. Add one 115/34.5 kV main step-up transformer (225 MVA) with a 115 kV breaker at Putnam BESS U1 substation to connect the BESS.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Construct approximately 0.3 miles string bus from Putnam switchyard 115 kV to Putnam BESS U1 substation.
2. No upgrades are expected to be necessary at this time.

III.E.14 Transmission Facilities for the Clover Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Clover Battery Energy Storage System Center in St. Lucie County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Clover Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.15 Transmission Facilities for the Sea Grape Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sea Grape Battery Energy Storage System Center in St. Lucie County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Muscadine Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.16 Transmission Facilities for the White Tail Battery Energy Storage System Center in Martin County

The work required to connect the approximate 74.5 MW (nameplate, AC) White Tail Battery Energy Storage System Center in Martin County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Strawberry Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.17 Transmission Facilities for the Fawn Battery Energy Storage System Center in Martin County

The work required to connect the approximate 74.5 MW (nameplate, AC) Fawn Battery Energy Storage System Center in Martin County in the 4th Quarter of 2026 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Fawn Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.18 Transmission Facilities for the Indrio Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Indrio Solar Energy Center in St. Lucie County in the 1st Quarter of 2027 is projected to be:

I. **Substation:**

1. Construct a new single bus, two (2) breaker 230 kV substation (Estuary) on the project site, adjacent to the new Sunbreak - Heritage 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Estuary substation.
3. Construct 34.5 kV bus to connect the PV array to Estuary 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. **Transmission:**

1. Loop the adjacent new Sunbreak - Heritage 230 kV into Estuary substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.19 Transmission Facilities for the Tangelo Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Tangelo Solar Energy Center in Okeechobee County in the 1st Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Clementine substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Clementine 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.20 Transmission Facilities for the Wood Stork Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Wood Stork Solar Energy Center in St. Lucie County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Liberty substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Liberty 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.21 Transmission Facilities for the Hendry Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Hendry Solar Energy Center in Hendry County in the 1st Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Ghost substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Ghost 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.22 Transmission Facilities for the Middle Lake Solar Energy Center in Madison County

The work required to connect the approximate 74.5 MW (nameplate, AC) Middle Lake Solar Energy Center in Madison County in the 1st Quarter of 2027 is projected to be:

I.Substation:

1. Extend 161 kV bus at Bandit substation to a new Sound substation and interconnect the 161/34.5kV transformer through a 161kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Sound Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II.Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.23 Transmission Facilities for the Spanish Moss Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Spanish Moss Solar Energy Center in St. Lucie County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Witt substation to a new Apricot substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Apricot 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.24 Transmission Facilities for the County Line Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) County Line Solar Energy Center in DeSoto County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Notts substation to a new Medieval substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Medieval 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.25 Transmission Facilities for the Saddle Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Saddle Solar Energy Center in DeSoto County in the 1st Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Ponna substation to a new Cheriot substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Cheriot 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.26 Transmission Facilities for the Swamp Cabbage Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Swamp Cabbage Battery Energy Storage System Center in Hendry County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Swamp Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.27 Transmission Facilities for the Green Pasture Battery Energy Storage System Center in Charlotte County

The work required to connect the approximate 74.5 MW (nameplate, AC) Green Pasture Battery Energy Storage System Center in Charlotte County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Zoysia Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.28 Transmission Facilities for the Blue Heron Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Blue Heron Battery Energy Storage System Center in Hendry County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Citron Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.29 Transmission Facilities for the Sawgrass Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sawgrass Battery Energy Storage System Center in Hendry County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Ghost Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.30 Transmission Facilities for the Terrill Creek Battery Energy Storage System Center in Clay County

The work required to connect the approximate 74.5 MW (nameplate, AC) Terrill Creek Battery Energy Storage System Center in Clay County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Terrill Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.31 Transmission Facilities for the Orange Blossom Battery Energy Storage System Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Orange Blossom Battery Energy Storage System Center in Indian River County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Finca Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.32 Transmission Facilities for the Hardwood Hammock Solar Energy Center in Walton County

The work required to connect the approximate 74.5 MW (nameplate, AC) Hardwood Hammock Solar Energy Center in Walton County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Quail substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Quail 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.33 Transmission Facilities for the Maple Trail Solar Energy Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Maple Trail Solar Energy Center in Baker County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Deodar substation to a new Maple substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Maple 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.34 Transmission Facilities for the Maple Trail Battery Energy Storage System Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Maple Trail Battery Energy Storage System Center in Baker County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Deodar Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.35 Transmission Facilities for the Indrio Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Indrio Battery Energy Storage System Center in St. Lucie County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Estuary Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.36 Transmission Facilities for the Monarch Battery Energy Storage System Center in Martin County

The work required to connect the approximate 74.5 MW (nameplate, AC) Monarch Battery Energy Storage System Center in Martin County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Gopher Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.37 Transmission Facilities for the Monarch ACES Battery Energy Storage System Center Pilot in Martin County

The work required to connect the approximate 10.0 MW (nameplate, AC) Monarch ACES Battery Energy Storage System Center Pilot in Martin County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Gopher Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.38 Transmission Facilities for the Swallowtail Battery Energy Storage System Center in Walton County

The work required to connect the approximate 74.5 MW (nameplate, AC) Swallowtail Battery Energy Storage System Center in Walton County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Swallowtail Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.39 Transmission Facilities for the Union Springs Battery Energy Storage System Center in Union County

The work required to connect the approximate 74.5 MW (nameplate, AC) Union Springs Battery Energy Storage System Center in Union County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Plum Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.40 Transmission Facilities for the Catfish Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Catfish Solar Energy Center in Okeechobee County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Pyrite substation to a new Catfish substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Catfish 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.41 Transmission Facilities for the Cocoplum Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Cocoplum Solar Energy Center in Hendry County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Witt substation to a new Mulberry substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Mulberry 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.42 Transmission Facilities for the Pinecone Solar Energy Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Pinecone Solar Energy Center in Calhoun County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Witt substation to a new Chinkapin substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Chinkapin 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.43 Transmission Facilities for the Myakka Solar Energy Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Myakka Solar Energy Center in Manatee County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Witt substation to a new Lemur substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Lemur 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.44 Transmission Facilities for the Joshua Creek Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Joshua Creek Solar Energy Center in DeSoto County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Witt substation to a new Stallion substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Stallion 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.45 Transmission Facilities for the Vernia Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Vernia Solar Energy Center in Indian River County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Construct a new single bus, three (3) breaker 230 kV substation (Vernia) on the project site, adjacent to the Sunbreak - Glint 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Vernia substation.
3. Construct 34.5 kV bus to connect the PV array to Vernia 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent Sunbreak - Glint 230 kV into Vernia substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.46 Transmission Facilities for the Ambersweet Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Ambersweet Solar Energy Center in Indian River County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Vernia substation to a new Ambersweet substation and interconnect the 230/34.5kV transformer through a 230kV breaker..
2. Construct 34.5 kV bus to connect the PV array to Ambersweet Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.47 Transmission Facilities for the Waveland Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Waveland Solar Energy Center in St. Lucie County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Waveland) on the project site, adjacent to the new Sunbreak - Heritage 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Waveland substation.
3. Construct 34.5 kV bus to connect the PV array to Waveland 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Sunbreak - Heritage 230 kV into Waveland substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.48 Transmission Facilities for the Inlet Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Inlet Solar Energy Center in Indian River County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Lumia) on the project site, adjacent to the new Waveland - Heritage 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Inlet substation.
3. Construct 34.5 kV bus to connect the PV array to Lumia 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Waveland - Heritage 230 kV into Lumia substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.49 Transmission Facilities for the Beachland Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Beachland Solar Energy Center in Indian River County in the 1st Quarter of 2028 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Finance substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Finance 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.50 Transmission Facilities for the Wabasso Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Wabasso Solar Energy Center in Indian River County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Finca substation to a new Finance substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Finance 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. Construct approximately 4.5 miles string bus from Finca 230 kV to Finance substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.51 Transmission Facilities for the Shores Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Shores Solar Energy Center in Indian River County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Finance substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Finance 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.52 Transmission Facilities for the Treefrog Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Treefrog Solar Energy Center in Collier County in the 1st Quarter of 2028 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.53 Transmission Facilities for the Honeybee Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Honeybee Solar Energy Center in Collier County in the 1st Quarter of 2028 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.54 Transmission Facilities for the Bromeliad Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Bromeliad Solar Energy Center in Collier County in the 1st Quarter of 2028 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.55 Transmission Facilities for the Sand Gully Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sand Gully Solar Energy Center in DeSoto County in the 1st Quarter of 2028 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Stallion substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Stallion 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.56 Transmission Facilities for the Pine Lily Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Pine Lily Solar Energy Center in St. Lucie County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Lily) on the project site, adjacent to the new Glint - Seville 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Lily substation.
3. Construct 34.5 kV bus to connect the PV array to Lily 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Glint - Seville 230 kV into Lilly substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.57 Transmission Facilities for the Pine Lily Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Pine Lily Battery Energy Storage System Center in St. Lucie County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Lily Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.58 Transmission Facilities for the Wild Lime Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Wild Lime Solar Energy Center in St. Lucie County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Lily substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Lily 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.59 Transmission Facilities for the Wild Lime Battery Energy Storage System Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Wild Lime Battery Energy Storage System Center in St. Lucie County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Lily Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.60 Transmission Facilities for the Waxweed Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Waxweed Solar Energy Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Waxweed) on the project site, adjacent to the new Puma - Keri 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Waxweed substation.
3. Construct 34.5 kV bus to connect the PV array to Waxweed 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Puma - Keri 230 kV into Waxweed substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.61 Transmission Facilities for the Waxweed Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Waxweed Battery Energy Storage System Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Waxweed Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.62 Transmission Facilities for the Owen Branch Solar Energy Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Owen Branch Solar Energy Center in Manatee County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Owen substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Owen 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.63 Transmission Facilities for the Owen Branch Battery Energy Storage System Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Owen Branch Battery Energy Storage System Center in Manatee County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Owen Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.64 Transmission Facilities for the Shell Creek Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Shell Creek Solar Energy Center in DeSoto County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Notts substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Notts 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.65 Transmission Facilities for the Shell Creek Battery Energy Storage System Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Shell Creek Battery Energy Storage System Center in DeSoto County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Notts Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.66 Transmission Facilities for the LaBelle Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) LaBelle Solar Energy Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Swamp substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Swamp 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.67 Transmission Facilities for the Cardinal Solar Energy Center in Brevard County

The work required to connect the approximate 74.5 MW (nameplate, AC) Cardinal Solar Energy Center in Brevard County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Goodwin substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Goodwin 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.68 Transmission Facilities for the Redroot Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Redroot Solar Energy Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Waxweed substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Waxweed 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.69 Transmission Facilities for the Redroot Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Redroot Battery Energy Storage System Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Waxweed Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.70 Transmission Facilities for the Mango Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Mango Solar Energy Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Towhee) on the project site, adjacent to the new Puma - Keri 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Towhee substation.
3. Construct 34.5 kV bus to connect the PV array to Towhee 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Puma - Keri 230 kV into Towhee substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.71 Transmission Facilities for the Mango Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Mango Battery Energy Storage System Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Towhee Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.72 Transmission Facilities for the Grapefruit Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Grapefruit Solar Energy Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Towhee substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Towhee 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.73 Transmission Facilities for the Grapefruit Battery Energy Storage System Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Grapefruit Battery Energy Storage System Center in Hendry County in the 3rd Quarter of 2028 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Towhee Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.74 Transmission Facilities for the Ladybug Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Ladybug Solar Energy Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend 230 kV bus at Stallion substation to a new Tern substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Tern 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. Construct approximately 8.0 miles string bus from Stallion 230 kV to Tern substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.75 Transmission Facilities for the Ladybug Battery Energy Storage System Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Ladybug Battery Energy Storage System Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Tern Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.76 Transmission Facilities for the Leafcutter Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Leafcutter Solar Energy Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend 230 kV bus at Tern substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Tern 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.77 Transmission Facilities for the Leafcutter Battery Energy Storage System Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Leafcutter Battery Energy Storage System Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Tern Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.78 Transmission Facilities for the Blanketflower Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Blanketflower Solar Energy Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend 230 kV bus at Tern substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Tern 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.79 Transmission Facilities for the Blanketflower Battery Energy Storage System Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Blanketflower Battery Energy Storage System Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Tern Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.80 Transmission Facilities for the Dove Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Dove Solar Energy Center in DeSoto County in the 1st Quarter of 2029 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation Dove on the project site, adjacent to the new Doorfield - Avon 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Dove substation.
3. Construct 34.5 kV bus to connect the PV array to Dove 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Doorfield – Avon 230 kV into Dove substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.81 Transmission Facilities for the Spoonbill Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Spoonbill Solar Energy Center in Collier County in the 1st Quarter of 2029 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.82 Transmission Facilities for the Limpkin Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Limpkin Solar Energy Center in Collier County in the 1st Quarter of 2029 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.83 Transmission Facilities for the New River Solar Energy Center in Union County

The work required to connect the approximate 74.5 MW (nameplate, AC) New River Solar Energy Center in Union County in the 3rd Quarter of 2029 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 115 kV substation Damson on the project site, adjacent to the Butler – Plum 115 kV line.
2. Add one 115/34.5 kV main step-up transformer (85 MVA) with a 115 kV breaker to connect PV inverter array at Damson substation.
3. Construct 34.5 kV bus to connect the PV array to Damson 115 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Butler - Plum 115 kV into Damson substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.84 Transmission Facilities for the Caladium Solar Energy Center in Highlands County

The work required to connect the approximate 74.5 MW (nameplate, AC) Caladium Solar Energy Center in Highlands County in the 3rd Quarter of 2029 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Condor) on the project site, adjacent to the Avon - Waterway 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Condor substation.
3. Construct 34.5 kV bus to connect the PV array to Condor 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Avon - Waterway 230 kV into Condor substation.
2. No additional upgrades are expected to be necessary at this time.

III.F. Renewable Resources and Storage Technology

FPL's Renewable Energy Efforts Through 2025:

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. Since 1976, FPL has been an industry leader in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. FPL's (including FPL NWFL) renewable energy efforts through 2025 are briefly discussed below in five categories of solar/renewable activities. Plans for new renewable energy facilities from 2026-2035 are then discussed in a separate section.

1) Early Research & Development Efforts:

In the late 1970s, FPL assisted the Florida Solar Energy Center (FSEC) in demonstrating the first residential PV system east of the Mississippi River. This PV installation at FSEC's Brevard County location was in operation for more than 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. In 1984, FPL installed a second PV system at its Flagami substation in Miami. This 10-kilowatt (kW) system operated for several years before it was removed to make room for substation expansion. In addition, FPL maintained a thin-film PV test facility at the FPL Martin Plant Site for several years to test new thin-film PV technologies.

2) Demand-Side & Customer Efforts:

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (because it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created to broadly disseminate information about passive solar building design techniques that are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, the program received a U.S.

Department of Energy award for innovation and led to a revision of the Florida Model Energy Building Code which was the incorporation of one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

FPL has continued to analyze and promote PV utilization. These efforts have included PV research, such as the 1991 research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. FPL's PV efforts also included educational efforts, such as FPL's Next Generation Solar Station Program. This initiative delivered teacher training and curriculum that was tied to the Sunshine Teacher Standards in Florida. The program provided teacher grants to promote and fund projects in the classrooms.

Gulf Power (Gulf) offered customers the opportunity to contribute to the development of solar beginning with the Solar for Schools program in its 1995 DSM Plan. This voluntary program ultimately developed multiple PV installations in schools across Northwest Florida and was used primarily for educational purposes. In 1999, Gulf offered customers an additional opportunity through an optional rate rider. The PV Rate Rider program was intended to give customers an opportunity to contribute towards the construction of a solar facility along with other customers across the Southern Company territory.

In 2008, Gulf received FPSC approval to offer an experimental solar water heating program. This program was intended to help customers overcome the high initial cost of adopting solar thermal water heating technology. The program spanned three years and was absorbed into a larger portfolio of renewable program offerings in Gulf's 2010 DSM Plan.

In 2009, as part of its DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a certain capped amount annually to facilitate demand-side solar water heater and PV applications. The annual spending caps for these applications over the five-year period was approximately $15.5 million per year for FPL and approximately $576,000 per year for Gulf. In response to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of three PV-based programs and three solar water heating-based programs, plus a Renewable Research and Demonstration project. Gulf received similar approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of two PV-based programs and two solar water heating-based programs. Analyses of the results by both FPL and Gulf from these pilot programs since their inception consistently showed that none of these pilot programs were cost-effective for customers using any of the three cost-effectiveness screening tests used by the State of Florida. As a result, consistent with the

FPSC's December 2014 DSM Goals Order No. PSC-14-0696-FOF-EU, these pilot programs expired on December 31, 2015.

Gulf conducted market research in 2015 indicating customer interest in a renewable energy alternative to private rooftop solar. After further research into innovative offerings across the industry, Gulf developed a subscription-based program model commonly known as community solar. Gulf received FPSC approval in 2016 for a Community Solar program intended to facilitate construction of a 1 MW facility in Northwest Florida once adequate subscriptions were secured. However, customer interest was not adequate enough to justify construction of the project.

In addition, FPL assists customers interested in installing solar equipment at their facilities. Consistent with Rule 25-6.065, F.A.C., Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned solar systems. Through December 2025, approximately 133,737 customer systems (predominantly residential) have been interconnected with FPL (including FPL NWFL). These values represent approximately 2% of FPL's total number of customer accounts.

3) Supply-Side Efforts – Power Purchases:

FPL has facilitated several renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.) through power purchase agreements (PPA). FPL purchases firm capacity and energy, and/or as-available energy, from these types of facilities. For example, FPL has a contract to receive firm capacity from the Solid Waste Authority of Palm Beach (SWA) through April 2034.

FPL currently has three PPAs with solar facilities totaling approximately 120 MW of nameplate capacity. In addition, FPL has two PPAs totaling approximately 81 MW based, at least in part, on receiving firm amounts of hourly energy from out-of-state sources that were originally wind-generated. Tables I.A.3.1, I.A.3.2, and I.A.3.3 in Chapter I provide information regarding both firm and non-firm capacity PPAs from renewable energy facilities in the two areas.

4) Supply Side Efforts – Utility Owned Facilities:

At the time this Site Plan is filed (April 1, 2026), FPL will own 116 universal solar generating facilities. All of these facilities are PV facilities and together they represent approximately 8,528 MW (nameplate) of generation for FPL. Each of these solar facilities is listed below in Table III.F.1.

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2026

	Solar Energy Center	County	Nameplate MW	Type	COD
1	DeSoto	DeSoto	25	Tracking	Oct-09
2	Space Coast	Brevard	10	Fixed	Apr-10
3	Manatee	Manatee	74.5	Fixed	Dec-16
4	Citrus	Desoto	74.5	Fixed	Dec-16
5	Babcock Ranch	Charlotte	74.5	Fixed	Dec-16
6	Horizon	Alachua/Putnam	74.5	Fixed	Jan-18
7	Coral Farms	Putnam	74.5	Fixed	Jan-18
8	Wildflower	DeSoto	74.5	Fixed	Jan-18
9	Indian River	Indian River	74.5	Fixed	Jan-18
10	Blue Cypress	Indian River	74.5	Fixed	Mar-18
11	Barefoot Bay	Brevard	74.5	Fixed	Mar-18
12	Hammock	Hendry	74.5	Fixed	Mar-18
13	Loggerhead	St. Lucie	74.5	Fixed	Mar-18
14	Miami-Dade	Miami-Dade	74.5	Fixed	Jan-19
15	Interstate	St. Lucie	74.5	Fixed	Jan-19
16	Sunshine Gateway	Columbia	74.5	Fixed	Jan-19
17	Pioneer Trail	Volusia	74.5	Fixed	Jan-19
18	Sweetbay	Martin	74.5	Fixed	Jan-20
19	Northern Preserve	Baker	74.5	Fixed	Jan-20
20	Cattle Ranch	DeSoto	74.5	Tracking	Jan-20
21	Twin Lakes	Putnam	74.5	Tracking	Jan-20
22	Blue Heron	Hendry	74.5	Fixed	Jan-20
23	Babcock Preserve	Charlotte	74.5	Fixed	Jan-20
24	Hibiscus	Palm Beach	74.5	Fixed	Apr-20
25	Okeechobee	Okeechobee	74.5	Fixed	Apr-20
26	Southfork	Manatee	74.5	Tracking	Apr-20
27	Echo River	Suwannee	74.5	Tracking	Apr-20
28	Blue Indigo	Jackson	74.5	Tracking	Apr-20
29	Lakeside	Okeechobee	74.5	Fixed	Dec-20
30	Trailside	St. Johns	74.5	Tracking	Dec-20
31	Union Springs	Union	74.5	Tracking	Dec-20
32	Egret	Baker	74.5	Tracking	Dec-20
33	Nassau	Nassau	74.5	Tracking	Dec-20
34	Magnolia Springs	Clay	74.5	Tracking	Mar-21
35	Pelican	St. Lucie	74.5	Fixed	Mar-21
36	Palm Bay	Brevard	74.5	Fixed	Mar-21
37	Rodeo	DeSoto	74.5	Tracking	Mar-21
38	Sabal Palm	Palm Beach	74.5	Fixed	Apr-21
39	Willow	Manatee	74.5	Tracking	May-21
40	Discovery	Brevard	74.5	Fixed	May-21
41	Orange Blossom	Indian River	74.5	Fixed	May-21
42	Fort Drum	Okeechobee	74.5	Fixed	Jun-21
43	Blue Springs	Jackson	74.5	Tracking	Dec-21
44	Cotton Creek	Escambia	74.5	Fixed	Dec-21

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2026, Continued

	Solar Energy Center	County	Nameplate MW	Type	COD
45	Ghost Orchid	Hendry	74.5	Fixed	Jan-22
46	Sawgrass	Hendry	74.5	Fixed	Jan-22
47	Sundew	St. Lucie	74.5	Fixed	Jan-22
48	Elder Branch	Manatee	74.5	Tracking	Jan-22
49	Grove	Indian River	74.5	Fixed	Jan-22
50	Immokalee	Collier	74.5	Fixed	Jan-22
51	Everglades	Miami-Dade	74.5	Fixed	Jan-23
52	Pink Trail	St. Lucie	74.5	Fixed	Jan-23
53	Bluefield Preserve	St. Lucie	74.5	Fixed	Jan-23
54	Cavendish	Okeechobee	74.5	Tracking	Jan-23
55	Anhinga	Clay	74.5	Tracking	Jan-23
56	Blackwater River	Santa Rosa	74.5	Fixed	Jan-23
57	Chipola River	Calhoun	74.5	Tracking	Jan-23
58	Flowers Creek	Calhoun	74.5	Tracking	Jan-23
59	First City	Escambia	74.5	Fixed	Jan-23
60	Apalachee	Jackson	74.5	Tracking	Jan-23
61	Wild Azalea	Gadsden	74.5	Tracking	Feb-23
62	Chautauqua	Walton	74.5	Tracking	Feb-23
63	Shirer Branch	Calhoun	74.5	Tracking	Feb-23
64	Saw Palmetto	Bay	74.5	Tracking	Apr-23
65	Cypress Pond	Washington	74.5	Tracking	Apr-23
66	Etonia Creek	Putnam	74.5	Tracking	Apr-23
67	Terrill Creek	Clay	74.5	Tracking	Jan-24
68	Silver Plam	Palm Beach	74.5	Tracking	Jan-24
69	Ibis	Brevard	74.5	Tracking	Jan-24
70	Orchard	Indian River/St. Lucie	74.5	Tracking	Jan-24
71	Beautyberry	Hendry	74.5	Tracking	Jan-24
72	Turnpike	Indian River	74.5	Tracking	Jan-24
73	Monarch	Martin	74.5	Tracking	Jan-24
74	Caloosahatchee	Hendry	74.5	Tracking	Jan-24
75	White Tail	Martin	74.5	Tracking	Jan-24
76	Prairie Creek	DeSoto	74.5	Tracking	Jan-24
77	Pineapple	St. Lucie	74.5	Tracking	Jan-24
78	Canoe	Okaloosa	74.5	Tracking	Jan-24
79	Sambucus	Manatee	74.5	Tracking	Mar-24
80	Sparkleberry	Escambia	74.5	Tracking	Mar-24
81	Three Creeks	Manatee	74.5	Tracking	Mar-24
82	Fourmile Creek	Calhoun	74.5	Tracking	Mar-24
83	Big Juniper Creek	Calhoun	74.5	Tracking	Mar-24
84	Pecan Tree	Walton	74.5	Tracking	Mar-24
85	Wild Quail	Walton	74.5	Tracking	Mar-24
86	Hawthorne Creek	DeSoto	74.5	Tracking	Mar-24
87	Nature Trail	Baker	74.5	Tracking	Mar-24
88	Woodyard	Hendry	74.5	Tracking	Mar-24

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2026, Continued

	Solar Energy Center	County	Nameplate MW	Type	COD
89	Honeybell	Okeechobee	74.5	Tracking	Nov-24
90	Buttonwood	St. Lucie	74.5	Tracking	Nov-24
91	Mitchell Creek	Escambia	74.5	Tracking	Nov-24
92	Hendry Isles	Hendry	74.5	Tracking	Nov-24
93	Georges Lake	Putnam	74.5	Tracking	Nov-24
94	Cedar Trail	Baker	74.5	Tracking	Nov-24
95	Norton Creek	Madison	74.5	Tracking	Dec-24
96	Kayak	Okaloosa	74.5	Tracking	Dec-24
97	Holowpaw	Palm Beach	74.5	Tracking	Jan-25
98	Speckled Perch	Okeechobee	74.5	Tracking	Jan-25
99	Big Water	Okeechobee	74.5	Tracking	Jan-25
100	Fawn	Martin	74.5	Tracking	Jan-25
101	Hog Bay	DeSoto	74.5	Tracking	Jan-25
102	Green Pasture	Charlotte	74.5	Tracking	Jan-25
103	Thomas Creek	Nassau	74.5	Tracking	Jan-25
104	Redlands	Miami-Dade	74.5	Fixed	Jan-25
105	Fox Trail	Brevard	74.5	Tracking	Jan-25
106	Long Creek	Manatee	74.5	Tracking	Jan-25
107	Swallowtail	Walton	74.5	Tracking	Jan-25
108	Tenmile Creek	Calhoun	74.5	Tracking	Jan-25
109	Big Brook	Calhoun	74.5	Tracking	Jan-26
110	Boardwalk	Collier	74.5	Tracking	Jan-26
111	Flatford	Manatee	74.5	Tracking	Jan-26
112	Goldenrod	Collier	74.5	Tracking	Jan-26
113	Mallard	Brevard	74.5	Tracking	Jan-26
114	Mare Branch	DeSoto	74.5	Tracking	Jan-26
115	Price Creek	Columbia	74.5	Tracking	Jan-26
116	Swamp Cabbage	Hendry	74.5	Tracking	Jan-26

5) Ongoing Research & Development Efforts:

FPL has a "Living Lab" across several of its office locations and select customer sites to demonstrate FPL's renewable energy commitment to employees and visitors. Through various Living Lab projects, FPL is able to evaluate multiple solar and storage technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses for FPL's customers. FPL currently has approximately 293 kW of PV as part of the Living Lab, including a 157 kW floating solar installation in Miami-Dade County that can enable FPL to compare generation and O&M costs for floating versus ground-mount solar. In 2020, FPL expanded the Living Lab to include residential sites around Palm Beach County to test battery storage in a residential setting. The test addresses both potential benefits of having a 5-to-8 kW storage system for home backup power and the ability of FPL to remotely control the storage systems to provide services to the electric grid. In 2021, FPL added solar paired with battery storage in a residential setting and 460 kW of linear generators. FPL plans to continue to expand the Living Lab as new technologies come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives, including ocean current, thermal storage, hydrogen, fuel cell technology, and energy storage.

Regarding solar's impact on the FPL system, FPL developed a methodology to determine what firm capacity value at FPL's Summer and Winter peak hours would be appropriate to apply to existing and potential solar facilities. The potential capacity contribution of solar facilities is dependent upon several factors including: site location, technology, design, and the total amount of solar that is operating on FPL's system.

Based on the results of its analyses using that methodology, firm capacity values are assigned to each new solar facility. These firm capacity values are described in terms of the percentage of the facility's nameplate (AC) rating that can be counted on as firm capacity at the Summer and Winter peak load hours. For example, two of FPL's earliest solar facilities, DeSoto and Space Coast, have been assigned firm capacity values of approximately 46% for DeSoto and 32% for Space Coast at FPL's Summer peak hour (that typically occurs in the 4 p.m. to 5 p.m. hour), but contribute firm capacity of only 3% for DeSoto and 1% for Space Coast during FPL's Winter peak hour (that typically occurs in the 7 a.m. to 8 a.m. hour). Similarly, each new solar facility is assigned a specific firm capacity value based on the factors described above. Information on each solar unit's firm capacity is available in the footnotes of Schedule 1 in Chapter I and the entries for new units in Schedule 8 later in this chapter. FPL will continue to

evaluate the firm capacity assigned to solar and battery facilities as it adapts more sophisticated resource adequacy methods like stochastic LOLP.

FPL has also conducted research on residential battery systems to evaluate both the potential to shift solar contribution to peak hours and to dispatch storage as a demand-response resource.

Renewable Energy, Battery Storage, and Electric Vehicle Projections for 2026 through 2035:

This section addresses efforts regarding renewable energy in both universal (utility-scale) and distributed solar, as well as FPL's SolarTogether™ program. In addition, efforts regarding battery storage are also addressed. These efforts and plans are summarized below.

1. Utility-Scale Solar:

In 2009, FPL constructed 110 MW of solar energy facilities including two PV facilities totaling 35 MW and one 75 MW solar thermal facility. This solar thermal facility location at the Martin plant, was retired in the 1st Quarter of 2023. From 2009 through 2017, the costs of solar equipment, especially PV equipment, declined significantly, and universal solar facilities became increasingly competitive economically with more conventional generation options. As a result, FPL added three new solar facilities of approximately 74.5 MW each near the end of 2016.

In the 1st Quarter of 2018, eight additional solar facilities of 74.5 MW each, or 596 MW in total, also went into commercial operation. These eight solar facilities were added under the Solar Base Rate Adjustment (SoBRA) provision of the Commission's order approving the settlement agreement for FPL's base rate case in 2016 (Order No. PSC-16-0560-AS-EI) and comprised two groups of four solar facilities each. In 2019, four more 74.5 MW solar facilities, or approximately 298 MW, were added as SoBRA facilities. An additional four 74.5 MW solar facilities, or approximately 298 MW, were placed into commercial operation in the 2nd Quarter of 2020. This completed the addition of solar under the 2016 SoBRA mechanism.

In the FPL NWFL service area, a total of three new 74.5 MW solar facilities were added. The first was placed into service in April 2020, and two additional sites achieved commercial operation in December of 2021.

As part of FPL's 2021 Rate Case Settlement (Order PSC-2021-0446-S-EI), the FPSC authorized FPL to construct 447 MW of solar in 2022 and an additional 745 MW of solar in 2023. The six sites totaling 447 MW in the 2022 group achieved commercial operation in January 2022. The ten additional sites comprising the 2023 group achieved commercial operation in January 2023.

Additionally, the Settlement also authorized FPL to construct 894 MW of solar in 2024 and 894 MW in 2025, for a total of 1,788 MW of solar, using a SoBRA mechanism identical in concept to the previous SoBRA. Each of these additions must be cost effective and fall below a cost cap of $1,250 kWac. The first 894 MW of solar for the 2024 SoBRA achieved commercial operation in January 2023, and the second 894 MW for the 2025 SoBRA achieved commercial operation in January 2025.

The resource plan presented in this Site Plan continues to show significant additions in solar resources over the ten-year reporting period. FPL's 2025 rate case settlement order (Order PSC-2026-0022-S-EI) allows for the construction of 5,364 MW from 2026 through 2029. In addition, FPL plans on adding 1,639 MW of additional solar in 2028 through 2030, as well as 3,055 MW in 2034 and 2035. In total, approximately 12,293 MW of additional solar generation is projected to be added in the 2026-2035 time period. The projected total of solar for the single integrated utility by the end of 2035 is equal to 20,225 MW.

Ongoing resource planning work will continue to analyze the projected system economics of solar and all other resource options. Information regarding the Preferred and Potential Sites for the projected PV additions, particularly in the near-term, is presented in Chapter IV and in the Appendix.

2. **Distributed PV Pilot Programs:**

FPL began implementation of two distributed PV pilot programs in 2015. The first is a voluntary, community-based, solar partnership pilot to install new solar-powered generating facilities. The program is funded by contributions from customers who volunteer to participate in the pilot and does not rely on subsidies from non-participating customers and has sunset as of December 31, 2025. The second program has installed approximately 3.4 MW of distributed generation (DG) PV and expired at the end of 2020. The objective of this second program was to collect grid integration data for DG PV and develop operational best practices for addressing potential problems that may be identified. The PV installed under this pilot program will continue to be evaluated for these purposes. A brief description of these pilot programs follows.

a. **Voluntary, Community-Based Solar Partnership Pilot Program:**

The Voluntary Solar Pilot Program, named FPL SolarNow™, provides FPL customers with a flexible opportunity to support solar power in Florida. The FPSC approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. The pilot program's tariff became effective in January 2015. The final program disposition and five-year extension of the pilot was approved on December 1, 2020, by the FPSC in Order No. PSC-2020-0508-TRF-EI, and the program has sunset on December 31, 2025.

This pilot program provided all customers the opportunity to support bringing solar projects into local communities by funding the construction of solar facilities in local public areas, such as parks, zoos, schools, and museums. Customers were formally able to participate in the program through voluntary contributions of $9/month. At conclusion of the program on December 31, 2025, there were 29,496 participants enrolled in the Voluntary Solar Pilot Program. Now that the program has concluded, the remaining installed 83 projects located in 34 communities within the FPL service area will continue to be managed utilizing shareholder funding and according to approved lease provisions. These remaining projects represent approximately 2,520 kW-DC of PV generation.

In addition to the SolarNow™ pilot program, FPL has also installed 121.6 kW (DC) of distributed solar generators at eight different locations and 5.4 kW (DC) of non-grid tied solar throughout the FPL NWFL territory.

b. **C&I Solar Partnership Pilot Program:**

This pilot program was conducted in partnership with interested commercial and industrial customers over an approximately five-year period and expired in 2020. Limited investments were made in PV facilities located at customer sites on selected distribution circuits within FPL's service area.

The primary objective was to examine the effect of high localized PV penetration on FPL's distribution system and to determine how best to address any problems that may be identified. FPL installed approximately 3.8 MW of PV facilities on circuits that experience specific loading conditions to better study feeder loading impacts, with approximately 3.4 MW remaining in operation. In addition, FPL evaluated the integration of solar into urban areas to test its impact on the distribution system on feeders that are heavily loaded.

3. **FPL SolarTogether™ Program:**

In March of 2019, FPL filed for FPSC approval of a community solar program under the market name FPL SolarTogether™. This voluntary program offers FPL customers the option to purchase solar output/attributes from cost-effective, large-scale solar energy centers. The proposed program did not require customers who participate to be bound to a long-term contract or subject to upfront enrollment costs or termination penalties. Under this program, participants' monthly electric bills would show both a subscription charge and a subscription credit line item associated with the subscribers' share of the actual solar energy generated. The FPL SolarTogether™ program was designed to leverage the economies of scale of universal solar to deliver long-term savings to both program participants and non-participants.

In March 2020, the FPSC approved the FPL SolarTogether™ program (Order PSC-2020-0084-S-EI). From 2020 through 2024, FPL has installed 3,278 MW of solar under the SolarTogether™ program. Approximately 1,005 MW has been allocated to residential customers, 2,190 MW has been allocated to commercial, industrial, and governmental customers, and 83 MW have been allocated to the low-income portion of SolarTogether™, marketed as FPL SunAssist™.

4. **Solar Power Facilities Pilot Program:**

As part of FPL's 2025 Settlement Agreement, FPL received approval to offer a permanent voluntary program to commercial and industrial customers that may elect to have FPL install and maintain a solar facility on their site for a monthly tariff charge (the "Solar Power Facilities Pilot Program"). The output of the solar facility is used solely by the participating customer. The fixed-term tariff recovers project capital costs and ongoing operating expenses through a monthly fixed charge paid by program participants, such that the general body of customers is not impacted. Over the last year, the program has deployed multiple assets throughout FPL's service territory and maintains a backlog of projects in various stages of the development lifecycle.

Battery Storage Efforts:

Battery storage technology has continued to advance and it continues to be cost-effective over the long-term, aided, in part, by continued tax credits. As a result, battery storage is an economically competitive firm capacity option for FPL's system. As previously discussed, a 409

MW battery storage facility was added in late 2021 at the existing Manatee plant site. Additional battery storage capacity was added in late 2021 with 30 MW of battery storage added at both the existing Sunshine Gateway Solar Energy Center and at the Echo River Solar Energy Center. In order to address local supply concerns in the NWFL region, FPL added 522 MW of battery storage in this area at the end of 2025. FPL's 2025 rate case settlement order (Order PSC-2026-0022-S-EI) allows for the construction of 3,431 MW from 2026 through 2029. A total of approximately 7,454 (nameplate) MW of battery storage is included in the resource plan for 2026 through 2035. These batteries help to minimize solar curtailment during shoulder load daytime hours and meet load demand in the evenings and in winter mornings. Batteries are also able to ramp up their output much faster than conventional generation, making them effective at meeting load demand as solar generation reduces during evening hours.

In addition, FPL is analyzing the potential of battery storage technology to benefit FPL's customers in other ways. These analyses have been, and are currently, being carried out through implementation of two pilot projects designed to evaluate different potential applications for batteries on FPL's system.

The objectives of the two pilot projects are to identify the most promising applications for batteries on FPL's system and to gain experience with battery installation and operation. This information will position FPL to expeditiously take advantage of battery storage for the benefit of FPL's customers as the economics of the technology continue to improve. For the purpose of discussing these two pilot projects, they will be referred to as the "small scale" and "large scale" storage pilot projects.

1. **Small Scale Storage Pilot Projects:**

In 2016 and early 2017, FPL installed approximately 4 MW of battery storage systems, spread across six sites, with the general objective of demonstrating the operational capabilities of batteries and learning how to integrate them into FPL's system. These small storage projects were designed with a distinct set of high-priority battery storage grid applications in mind. These applications include peak shaving, frequency response, and backup power. In addition, these initial projects were designed to provide FPL with an opportunity to determine how to best integrate storage into FPL's operational software systems and how best to dispatch and/or control the storage systems.

To this end, FPL installed multiple projects that have been in service for more than eight years and have yielded valuable information regarding the applications listed above. These projects

and learnings from them include: (i) a 1.5 MW battery in Miami-Dade County using second life automotive batteries for peak shaving and frequency response (found that high in-house integration costs coupled with low remaining capacity in second-life batteries do not support the business case), (ii) a 1.5 MW battery in Monroe County for backup power and voltage support (showcased the complexity of working with customer's equipment), (iii) a relocatable 0.75 MW uninterruptible power supply (UPS) battery at Trividia Health, Inc. in Broward County (provides consistent support to mitigate customer's momentary disruptions and reliability issues, but relocation is costly and requires high technical expertise), and (iv) smaller kilowatt-scale systems in several communities for distributed storage reliability (applications successfully provide reliability support for residential customers during grid events, but FPL found front-of-the-meter deployment is more expensive than behind the meter (BTM) installations). FPL decommissioned the 1.5 MW battery in in Miami-Dade County, the 0.75 MW UPS, and the small kilo-watt scale systems in several communities at the end of 2022.

2. **Large Scale (50 MW) Storage Pilot Project:**

The small-scale battery storage pilot projects described above are complemented by up to 50 MW of additional battery projects. These pilot projects were authorized under the Settlement Agreement in FPL's 2016 base rate case. The 50 MW of batteries that have been, and will continue, to be deployed in this larger pilot project have expanded the number of storage applications and configurations that FPL will be able to test and have made the scale of deployment more meaningful given the large size of FPL's system.

The first two storage projects under this pilot, placed in-service in the 1st Quarter of 2018, involve pairing battery storage with existing universal solar facilities. One of the projects is a 4 MW battery sited at FPL's Citrus Solar Energy Center. This project captures clipped solar energy from the solar panels during high solar insolation hours, then releases this energy in other hours. The second project is a 10 MW battery at FPL's Babcock Ranch Solar Energy Center. This project is designed to shift solar output from non-peak times to peak times and to provide "smoothing" of solar output and regulation services. These two projects are designed to enhance the operations of existing solar facilities that were installed in 2016. The data and lessons gathered from these two projects enable more optimized design configurations for solar-paired battery projects as well as improved operational parameters for economic dispatch. In 2021, FPL added an additional 1 MW to the existing Babcock Ranch Battery Storage System to test the design and performance of various battery augmentation solutions to mitigate degradation.

In the 4th Quarter of 2019, a 10 MW battery in Wynwood, a dense urban area close to downtown Miami, went into service. The project is designed to examine the use of batteries to support the distribution system with a focus on addressing grid, system, and customer challenges. Key learnings relate to the challenges of installing a battery in a dense urban area, including the decision to install in a building to allow for increased energy density, and integration into the distribution control system to allow for seamless integration into the Automated Feeder Switching system.

Two additional projects placed in-service in 2020 are designed to enhance reliability for FPL customers and the grid. One is an 11.5 MW battery that will augment the Dania Beach Clean Energy Center Unit 7. This project evaluates the use of battery storage to black start large generating units. The other is a 3 MW battery alongside an existing solar system to create a microgrid. The microgrid will be used for local resiliency and to provide additional grid services, including mitigation of disruptions potentially caused by solar in the distribution system. The projects have thus far yielded valuable learnings about interconnection approach and properly sizing the battery to account for the inrush current needed to energize the load for these applications.

The last three projects explore battery storage opportunities associated with EVs and EV infrastructure. The first explores the potential for utilizing EVs as grid resources on FPL's system for the first time ever; the 1.25 MW of Electric-Vehicle-to-Grid (EV2G) batteries using electric school buses will be able to discharge electricity to the grid when needed. The first two buses were delivered in the 3rd Quarter of 2020 and 1st Quarter of 2021; the remaining three buses, delayed due to supply chain constraints, were delivered in 2nd Quarter of 2024. The second EV plus storage pilot adds 0.35 MW of battery storage to two FPL EVolution® pilot sites in Columbia County and Nassau County (0.7 MW total) to provide grid benefits in the form of peak shaving and a reduction in distribution upgrades. The third and final pilot project, the "FPL EVolution® Hub", has two parts: (i) 7.25 MW of storage paired with 5 MW solar to create a renewable microgrid, and (ii) two trailers each fitted with 0.65 MW (total 1.3 MW) of storage and 6 EV (12 total) fast chargers. The microgrid will be used to charge the trailers that will be deployed throughout FPL service area during grid events to increase resiliency for EV charging. The microgrid will also be used to provide electricity to a nearby administrative building, warehouse, and several biodiesel tanks when not being used to charge the battery trailers. The first and third pilot projects have completed construction and are operational as of 2022. The EV + Storage project in Columbia and Nassau counties was placed into service in the 1st Quarter in 2024.

A summary of FPL's battery storage facilities is presented in Table III.F.2 below.

Table III.F.2: List of FPL Battery Storage Facilities

In-Service Date	Location/Projects	Status	Nameplate MW
2016-2017	2016 Pilots	Operational	1.5
2018	Citrus Solar Energy Center	Operational	4
2018	Babcock Ranch Solar Energy Center	Operational	10
2019	Wynwood	Operational	10
2020	Dania Beach Energy Center	Operational	11.5
2020	University Microgrid	Operational	3
2020	EV2G	Operational	1.25
2021	Manatee	Operational	409
2021	Sunshine Gateway	Operational	30
2021	Echo River	Operational	30
2022	FPL Evolution® Hub	Operational	8.55
2023	EV + Storage	Operational	0.7
2025	Big Juniper Battery Storage	Operational	74.5
2025	Kayak Battery Storage	Operational	74.5
2025	Canoe Battery Storage	Operational	74.5
2025	Chipola Battery Storage	Operational	74.5
2025	Fourmile Creek Battery Storage	Operational	74.5
2025	Shirer Branch Battery Storage	Operational	74.5
2025	Tenmile Creek Battery Storage	Operational	74.5
		Total:	**1,041**

Electric Vehicle Efforts:

Florida is ranked second in the nation for EV adoption, and more Floridians are buying EVs every year with 96% of current BEV owners saying they would consider purchasing/leasing another EV in the future. FPL began implementation of the FPL EVolution® pilot program in 2019 to support the growth of EVs with the goal to install more than 1,000 charging ports. The primary objective of this pilot program for FPL is to gather data and learnings ahead of projected mass EV adoption to ensure future EV investments enhance service and reduce costs. The FPL EVolution® Pilot focuses on three key areas: a) influences of infrastructure build-out on adoption; b) rate structures and demand models; and c) grid impacts of fast-charging. This pilot program is being conducted in partnership with interested host customers over an approximate three-year period. Installations encompass different EV charging technologies and market segments, including level 2 workplace charging at public and/or private workplaces; destination charging at well-attended locations; residential charging at customers' homes; and fast charging in high-traffic areas, along highway corridors and evacuation routes to enable long

distance travel. These places include Florida's Turnpike Service Plazas, public parking areas, tourist attractions, hospitals, and large businesses that employ hundreds of Florida residents.

As part of FPL's 2021 Settlement Agreement, FPL received approval to expand the initial FPL EVolution® Pilot and add additional EV programs that were launched in 2022, including: i) public fast charging, ii) new technologies and software, iii) education and outreach, iv) a voluntary residential EV charging services tariff, and v) a voluntary fleet EV charging services tariff.

In addition, pursuant to Order No. 2020-0512-TRF-EI, issued December 21, 2020, FPL has implemented three optional five-year EV public charging pilot tariffs. The first tariff, Utility-Owned Public Charging for Electric Vehicles (Rate Schedule UEV), establishes a rate for FPL to charge drivers directly at certain utility-owned FPL EVolution® fast charging stations. The second set of tariffs, Electric Vehicle Charging Infrastructure Riders to General Service Demand and General Service Large Demand (Rate Schedules GSD-1EV and GSLD-1EV), limit the demand cost associated with general service demand rates billed to third-party public charging stations operating in FPL's service area. The tariffs took effect in January 2021 and will last for a period of five years.

As of December 31, 2025, FPL EVolution® Public has installed 910 Level 2 charging ports and 321 fast charging ports. There are 76 FPL EVolution fast charging sites operating under the UEV rate schedule and approximately 200 additional ports expected to be online by the end of 2026. FPL has also added 274 charging ports under the fleet pilot in 2024 and 30 Level 2 charging ports under the CEVCS-1 tariff in 2025. Additionally, FPL added 9,007 Level 2 chargers for residential customers, allowing managed EV charging during off-peak hours, avoiding additional load during peak. Furthermore, the 2025 rate case settlement modified the existing EV programs in various ways. First, it made the demand-limiter tariffs permanent and added a new demand limiter tariff, GSLD-2EV, for very large charging sites. The public fast charging pilot came to an end, port count was capped at 585 ports, and pricing was increased from $0.30/kWh to $0.45/kWh following an increasing schedule. A new "Make-Ready Credit" program was also approved that accelerates site economics for new charging providers by offsetting utility upgrade costs. The Residential EV Home tariffs (RS-1EV/RS-2EV) were approved subject to repricing to better align program costs and revenues. Finally, the PSC extended FPL's Fleet pilot program and the associated CEVCS-1 tariff. The FPL EVolution® pilot has provided FPL valuable early insights and best practices into EV charging infrastructure deployment in the areas of siting, equipment, installation, and grid reliability.

III.G Fuel Mix and Fuel Price Forecasts

1. FPL Fuel Mix

FPL's fuel mix since the early 1990s has seen a steady increase in the amount of natural gas, which FPL uses to produce electricity due, in part, to the introduction of highly efficient and cost-effective CC units and the ready availability of abundant, U.S.-produced natural gas. Since 2001, FPL has focused on modernizing its gas-fired generation fleet by modernizing existing units and adding CC units to its generation mix. These new CC units have dramatically improved the efficiency of FPL's generation system in general and, more specifically, the efficiency with which natural gas is utilized as discussed in the Executive Summary.

In regard to access to alternative fuel availability, the addition of four CTs at the Gulf Clean Energy Center in 2021, capable of burning natural gas or ULSD oil, has also provided additional fuel diversity and reliability.

FPL has also taken measures over the last few years to eliminate the use of coal as a fuel. FPL shuttered Cedar Bay in 2016, St. Johns River Power Park in 2018, the Indiantown Co-Gen coal-fueled unit in late 2020, and the Scherer 4 unit on January 1, 2022. The conversion of the Gulf Clean Energy Center to natural gas in 2020, plus the retirement of FPL's ownership portion of the Daniel Units 1 & 2 in January 2024 demonstrates a continued commitment to eliminate coal from the generation portfolio.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 500 MW of additional nuclear capacity have been added to the FPL system. As mentioned previously, FPL has obtained the COLs from the NRC for two new nuclear units, Turkey Point Units 6 & 7. FPL has now paused this process to decide when to pursue approval from the FPSC to proceed to construction.

A significant amount of additional solar is projected in the current resource plan as discussed throughout this Site Plan. These solar additions will increase solar as a percentage of FPL's generation from 11% in 2025 to 26% in 2035.

Ongoing resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance long-term fuel diversity and resiliency. These fuel-diverse alternatives may include additional solar energy facilities;

obtaining additional access to diversified sources of natural gas from the Mid-Continent, Marcellus, and Permian producing regions; preserving the ability to utilize fuel oil at existing units; increased utilization of nuclear energy; and the purchase of power from renewable energy facilities. Resiliency-focused efforts include enhancing natural gas supply resiliency, including liquefied natural gas (LNG) arrangements for peak needs. The evaluation of the feasibility and cost-effectiveness of these and other possible fuel diversity alternatives will be part of on-going resource planning efforts.

As part of the effort to introduce further fuel diversity and resiliency into FPL's generation system, a green hydrogen electrolysis pilot project has been developed and deployed at FPL's Okeechobee CC unit. This pilot utilizes solar energy to perform electrolysis and generate hydrogen fuel. This hydrogen fuel is then burned in a portion of the CC unit to test the capability of FPL's existing units to burn hydrogen instead of natural gas. This pilot allows FPL to assess how the CTs in a CC unit operate with a hydrogen and natural gas fuel mix, and it also provides insight into how a hydrogen fuel production and storage facility can be effectively used on site with combustion turbine units. To provide a source of hydrogen to burn for this pilot, FPL built an approximate 25 MW electrolyzer and a storage facility for the production and on-site storage of hydrogen at Okeechobee. The electrolyzer is interconnected with renewable generation at the Okeechobee site so that electrical energy from a solar facility can be used by the electrolyzer to separate water into hydrogen and oxygen gases. The oxygen is released into the air while the hydrogen is compressed and stored on-site where it can later be used as fuel in the CT units at the Okeechobee site. This pilot project went into service in late 2023.

Current use of various fuels to supply energy to customers, plus projections of this "fuel mix" through 2035 based on the resource plan presented in this document, are presented in Schedules 5, 6.1, and 6.2 that appear later in this chapter.

2. Fossil Fuel Cost Forecasts

FPL's Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used to evaluate alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. A September 2025 fuel cost forecast was used in the analyses which developed the resource plans presented in this 2026 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscore the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, Low, Medium, and High price forecasts for fossil fuels were developed in anticipation of the 2026 resource planning work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For the then-current plus two years (2025-2027), the methodology used the September 2025 forward curve for New York Harbor 0.5% sulfur heavy oil, WTI Crude Oil, Ultra-Low Sulfur Diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices (As S&P Global no longer publishes a Long Term forecast for 0.7% Sulfur Heavy Oil, FPL now forecasts a 0.5% Sulfur heavy oil price using a combination of market quotes and 1% Sulfur heavy oil price forecasts);

b. For the next two years (2028 and 2029), FPL used a 50/50 blend of the September 2025 forward curve and the most current projections at the time from S&P Global (formerly called The PIRA Energy Group);

c. For the 2030-2050 period, FPL used the annual projections from S&P Global for oil and natural gas commodity prices;

d. For the period beyond 2050 for oil and natural gas, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. FPL uses a combination of actual coal purchases, current market quotes provided to FPL, Long Term PRB Coal price forecast up to 2050 from S&P Global and rail rate growth from historical data to build a coal price forecast for Plant Scherer.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. FPL's approach has been to then adjust the Medium fuel cost forecast upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

3. Natural Gas Storage

Beginning April 1, 2026, FPL will have 5.0 billion cubic feet (Bcf) of firm natural gas storage capacity at the Bay Gas storage facility in Alabama through March 31, 2032. Also, effective April 1, 2026, FPL's storage contract with SG Resources Mississippi, LLC (Southern Pines Storage) increased from 1 Bcf to 3 Bcf, and the contract is set to expire on March 31, 2030. In 2025, FPL added an incremental 2 Bcf of storage at Petal Storage located in Mississippi; the contract currently extends through March 31, 2030 and increases from 2 Bcf to 3 Bcf beginning April 1, 2030 though April 2036. Southern Pines and Petal storage provide diversity to FPL's storage portfolio and access to numerous pipeline systems serving FPL. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems.

FPL's ability to manage the daily "swings" in natural gas demand that can occur on its system due to weather and unit availability changes is challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide the ability to manage its supply and demand on a daily basis. The gas storage portfolio is continually evaluated and subscription for additional gas storage capacity is possible if needed to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas

Reliance upon natural gas to produce electricity for FPL's customers is projected to continue for a number of years due to FPL's growing load.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies: FGT and Gulfstream. In mid-2017, a third new pipeline system, consisting of the Sabal Trail and Florida Southeast Connection pipelines, went into operation. This new pipeline system is now providing fuel for FPL's Riviera, Okeechobee, and Martin plants. The new pipeline system will also allow needed support for gas-fueled FPL generation facilities in several counties.

5. Nuclear Fuel Cost Forecast

This section discusses the various steps needed to fabricate nuclear fuel for delivery to nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U_3O_8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U_3O_8 is chemically converted into UF_6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms.

Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.0% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF_6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF_6 is changed to a UO_2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion into a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market because the majority of the Japanese nuclear reactors are still not operating. As a result, current demand has remained declined and several of the production facilities have either closed or announced delays. Factors of importance are:

- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain DOE facilities.
- Although only two new nuclear units are starting production in the U.S. in the short-term, other countries have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a ten-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture remains stable, with laws enacted in 2020 to resolve the import of Russian-enriched uranium, by allowing continued imports of Russian-enriched uranium to meet about 15-24% of needs from 2026-2040 for currently operating and new units. New and current uranium production facilities are decreasing capacity due to continued low prices and demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future

periodic sharp increases in prices but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production is currently forecasted to be insufficient to meet a higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond the current level if more firm commitments are made. FPL expects long-term price stability for conversion services to support world demand.

(3) Enrichment: Since the Fukushima events in March 2011, the near-term price of enrichment services has declined. However, plans for construction of several new facilities that were expected to come on-line after 2011 have been delayed and/or cancelled. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects an adequate supply of enrichment services. The current supply/demand profile will likely result in the price of enrichment services remaining stable for the next few years, then starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the NRC, not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand are expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. There is adequate projected supply, including planned and prospective mine expansions, to meet FPL demands, including operation of the two Turkey Point nuclear units, even through the 2052 and 2053 dates that are a part of FPL's SLR requests for these units.

Schedule 5: Actual
Fuel Requirements

Fuel Requirements	Units	Actual [1/] FPL 2024	Actual [1/] FPL 2025
(1) Nuclear	Trillion BTU	301	318
(2) Coal	1,000 TON	372	313
(3) Residual (FO_6) - Total	1,000 BBL	0	0
(4) Steam	1,000 BBL	0	0
(5) Distillate (FO_2) - Total	1,000 BBL	178	90
(6) Steam	1,000 BBL	0	0
(7) CC	1,000 BBL	51	38
(8) CT	1,000 BBL	127	52
(9) Natural Gas - Total	1,000 MCF	742,232	705,980
(10) Steam	1,000 MCF	26,133	21,638
(11) CC	1,000 MCF	697,665	673,229
(12) CT	1,000 MCF	18,434	11,114
(13) Hydrogen [2/]	Trillion BTU	0.10	0.00
(14) Other [3/]	1,000 MCF	160	177

1/ Source: A Schedules.
2/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
3/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 5: Forecasted
Fuel Requirements

Fuel Requirements	Units	Forecasted									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
		FPL									
(1) Nuclear	Trillion BTU	300	302	308	306	307	306	308	306	307	306
(2) Coal	1,000 TON	463	349	390	249	235	358	667	519	656	671
(3) Residual (FO_6) - Total	1,000 BBL	1	3	0	0	8	1	0	0	0	0
(4) Steam	1,000 BBL	1	3	0	0	8	1	0	0	0	0
(5) Distillate (FO_2) - Total	1,000 BBL	11	10	14	9	12	5	4	3	2	3
(6) Steam	1,000 BBL	11	9	14	9	11	5	4	3	2	3
(7) CC	1,000 BBL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CT	1,000 BBL	0.0	0.6	0.2	0.0	1.7	0.0	0.0	0.0	0.0	0.0
(9) Natural Gas - Total	1,000 MCF	654,535	646,158	639,326	641,587	607,116	635,073	662,454	696,534	701,967	704,151
(10) Steam	1,000 MCF	12,704	9,089	8,358	8,317	8,974	8,175	5,048	5,736	7,426	8,037
(11) CC	1,000 MCF	632,891	631,752	628,216	629,001	593,985	623,465	653,014	687,244	686,941	684,980
(12) CT	1,000 MCF	8,940	5,317	2,752	4,269	4,157	3,433	4,392	3,553	7,600	11,135
(13) Hydrogen [2/]	1,000 MCF	0	0	0	0	0	0	0	0	0	0
(14) Other [3/]	1,000 MCF	15	12	13	18	0	0	0	0	0	0

1/ Source: A Schedules.
2/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program - FPL does not include Hydrogen in it's forecasted fuel requirements.
3/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1 Actual
Energy Sources

	Energy Sources	Units	Actual [1/] FPL 2024	FPL 2025
(1)	Annual Energy Interchange [2/]	GWH	0	0
(2)	Nuclear	GWH	28,009	29,384
(3)	Coal	GWH	533	479
(4)	Residual(FO_6) -Total	GWH	0.0	0.0
(5)	Steam	GWH	0	0
(6)	Distillate(FO_2) -Total	GWH	116.4	56.4
(7)	Steam	GWH	9	3
(8)	CC	GWH	43	31
(9)	CT	GWH	64	22
(10)	Natural Gas -Total	GWH	104,335	99,427
(11)	Steam	GWH	2,074	1,645
(12)	CC	GWH	100,515	96,718
(13)	CT	GWH	1,747	1,064
(14)	Solar [3/]	GWH	12,404	16,738
(15)	PV	GWH	6,929	9,634
(16)	Solar Together [4/]	GWH	5,260	6,869
(17)	Solar PPAs	GWH	215	234
(18)	Wind PPAs	GWH	1,029	838
(19)	Hydrogen Gas [5/]	GWH	15.76	42
(20)	Other [6/]	GWH	(356)	297
	Net Energy For Load [7/]	GWH	146,103	147,271

1/ Sources: Actuals for FPL and FPL NWFL: A Schedules and Actual Data for Next Generation Solar Centers Report.

2/ Represents interchange between FPL/FPL NWFL and other utilities. For FPL NW, this number represents the net energy exchange with Southern Co.

3/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.

4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.

5/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program

6/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the LFG generation from the Perdido unit.

7/ Net Energy For Load values for the years 2024 and 2025 are shown in column (2) on Schedule 3.3 History of Annual Net Energy for Load

Schedule 6.2 Actual
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1/] FPL 2024	FPL 2025
(1)	Annual Energy Interchange [2/]	%	0.0	0.0
(2)	Nuclear	%	19.2	20.0
(3)	Coal	%	0.4	0.3
(4)	Residual (FO_6) -Total	%	0.0	0.0
(5)	Steam	%	0.0	0.0
(6)	Distillate (FO_2) -Total	%	0.1	0.0
(7)	Steam	%	0.0	0.0
(8)	CC	%	0.0	0.0
(9)	CT	%	0.0	0.0
(10)	Natural Gas -Total	%	71.4	67.5
(11)	Steam	%	1.4	1.1
(12)	CC	%	68.8	65.7
(13)	CT	%	1.2	0.7
(14)	Solar [3/]	%	8.5	11.4
(15)	PV	%	4.7	6.5
(16)	Solar Together [4/]	%	3.6	4.7
(17)	Solar PPAs	%	0.1	0.2
(18)	Wind PPAs	%	0.7	0.6
(19)	Hydrogen Gas [5/]	%	0.0	0.0
(20)	Other [6/]	%	(0.2)	0.2
			100	100

1/ Sources: Actuals for FPL and FPL NWFL: A Schedules and Actual Data for Next Generation Solar Centers Report.

2/ Represents interchange between FPL/FPL NWFL and other utilities. For FPL NW, this number represents the net energy exchange with Southern Co.

3/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.

4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.

5/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program

6/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the LFG generation from the Perdido unit.

7/ Net Energy For Load values for the years 2024 and 2025 are shown in column (2) on Schedule 3.3 History of Annual Net Energy for Load

Schedule 6.1 Forecasted
Energy Sources

			FPL									
	Energy Sources	**Units**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	Annual Energy Interchange [1/]	GWH	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear	GWH	28,504	28,613	29,224	29,029	29,139	29,033	29,220	29,031	29,141	29,027
(3)	Coal	GWH	736	553	618	392	368	566	1,064	828	1,048	1,071
(4)	Residual(FO_6) -Total	GWH	0	2	0	0	5	1	0	0	0	0
(5)	Steam	GWH	0	2	0	0	5	1	0	0	0	0
(6)	Distillate(FO_2) -Total	GWH	6	5	5	3	4	2	1	1	1	1
(7)	Steam	GWH	4	4	5	3	4	2	1	1	1	1
(8)	CC	GWH	0	0	0	0	0	0	0	0	0	0
(9)	CT	GWH	2	1	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	95,280	95,051	94,518	94,497	88,539	92,903	97,210	102,413	103,086	103,049
(11)	Steam	GWH	1,183	855	782	785	849	773	477	544	704	763
(12)	CC	GWH	93,242	93,684	93,474	93,302	87,290	91,801	96,316	101,531	101,659	101,230
(13)	CT	GWH	855	511	262	410	400	329	417	338	723	1,057
(14)	Solar [2/]	GWH	19,382	21,395	24,845	29,886	39,932	39,793	39,747	39,502	43,055	46,767
(15)	PV	GWH	11,933	13,972	17,429	22,514	32,586	32,472	32,437	32,237	35,811	39,548
(16)	Solar Together [3/]	GWH	7,229	7,204	7,197	7,154	7,128	7,104	7,094	7,050	7,029	7,005
(17)	Solar PPAs	GWH	220	219	219	218	217	217	216	215	215	214
(18)	Wind PPAs	GWH	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031	1,031	1,031
(19)	Hydrogen Gas [4/]	GWH	0	0	0	0	0	0	0	0	0	0
(20)	Other [5/]	GWH	1,557	1,033	991	932	893	809	584	533	130	(269)
	Net Energy For Load [6/]	GWH	146,498	147,683	151,235	155,772	159,911	164,138	168,858	173,338	177,492	180,678

1/ Represents interchange between FPL and other utilities.
2/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.
3/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.
4/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the Perdido Unit projected generation.
6/ Net Energy For Load values for the years 2023 and 2024 are shown in column (2) on Schedule 3.3 History of Annual Net Energy for Load and values for 2025 - 2034 are shown in Col. (2) on Schedule 3.3 Forecast of Annual Net Energy for Load.

Schedule 6.2 Forecasted
Energy Sources % by Fuel Type

		FPL									
Energy Source	**Units**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1) Annual Energy Interchange [1/]	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.5	19.4	19.3	18.6	18.2	17.7	17.3	16.7	16.4	16.1
(3) Coal	%	0.5	0.4	0.4	0.3	0.2	0.3	0.6	0.5	0.6	0.6
(4) Residual (FO_6) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6) Distillate (FO_2) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	65.0	64.4	62.5	60.7	55.4	56.6	57.6	59.1	58.1	57.0
(11) Steam	%	0.8	0.6	0.5	0.5	0.5	0.5	0.3	0.3	0.4	0.4
(12) CC	%	63.6	63.4	61.8	59.9	54.6	55.9	57.0	58.6	57.3	56.0
(13) CT	%	0.6	0.3	0.2	0.3	0.3	0.2	0.2	0.2	0.4	0.6
(14) Solar [2/]	%	13.2	14.5	16.4	19.2	25.0	24.2	23.5	22.8	24.3	25.9
(15) PV	%	8.1	9.5	11.5	14.5	20.4	19.8	19.2	18.6	20.2	21.9
(16) Solar Together [3/]	%	4.9	4.9	4.8	4.6	4.5	4.3	4.2	4.1	4.0	3.9
(17) Solar PPAs	%	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(18) Wind PPAs	%	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6
(19) Hydrogen Gas [4/]	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(20) Other [5/]	%	1.1	0.7	0.7	0.6	0.6	0.5	0.3	0.3	0.1	-0.1
		100	100	100	100	100	100	100	100	100	100

1/ Represents interchange between FPL and other utilities.
2/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.
3/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.
4/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the Perdido Unit projected generation.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
2026	33,205	239	0	4	33,448	28,868	1,910	26,958	6,490	24.1	0	6,490	24.1	4,580	15.9
2027	35,517	239	0	0	35,756	29,259	1,916	27,343	8,412	30.8	0	8,412	30.8	6,496	22.2
2028	36,001	239	0	0	36,239	30,033	1,932	28,101	8,139	29.0	0	8,139	29.0	6,207	20.7
2029	36,466	239	0	0	36,705	30,682	1,949	28,733	7,971	27.7	0	7,971	27.7	6,022	19.6
2030	36,799	238	0	0	37,037	31,325	1,973	29,352	7,685	26.2	0	7,685	26.2	5,712	18.2
2031	37,404	238	0	0	37,642	32,175	2,000	30,175	7,468	24.7	0	7,468	24.7	5,468	17.0
2032	38,558	198	0	0	38,756	33,115	2,027	31,088	7,669	24.7	0	7,669	24.7	5,642	17.0
2033	39,725	198	0	0	39,922	34,038	2,055	31,983	7,940	24.8	0	7,940	24.8	5,885	17.3
2034	40,811	127	0	0	40,938	34,874	2,084	32,790	8,148	24.8	0	8,148	24.8	6,064	17.4
2035	41,657	127	0	0	41,784	35,623	2,107	33,516	8,267	24.7	0	8,267	24.7	6,160	17.3

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2025-on intended for use with the 2026 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
2026	30,448	449	0	4	30,901	23,478	1,471	22,007	8,894	40.4	0	8,894	40.4	7,423	31.6
2027	31,888	219	0	0	32,107	23,962	1,473	22,489	9,618	42.8	0	9,618	42.8	8,145	34.0
2028	33,421	219	0	0	33,640	24,515	1,482	23,033	10,607	46.1	0	10,607	46.1	9,125	37.2
2029	34,290	219	0	0	34,509	25,070	1,495	23,575	10,934	46.4	0	10,934	46.4	9,439	37.7
2030	35,249	219	0	0	35,468	25,405	1,509	23,895	11,573	48.4	0	11,573	48.4	10,064	39.6
2031	36,440	219	0	0	36,659	26,018	1,530	24,488	12,171	49.7	0	12,171	49.7	10,641	40.9
2032	37,952	219	0	0	38,171	26,716	1,551	25,165	13,006	51.7	0	13,006	51.7	11,455	42.9
2033	39,478	179	0	0	39,657	27,404	1,572	25,832	13,825	53.5	0	13,825	53.5	12,253	44.7
2034	40,673	179	0	0	40,852	28,000	1,594	26,407	14,445	54.7	0	14,445	54.7	12,852	45.9
2035	41,999	109	0	0	42,108	28,544	1,615	26,928	15,180	56.4	0	15,180	56.4	13,564	47.5

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet Winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2025-on intended for use with the 2026 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Transport Pri.	(8) Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability [2/] Winter MW	(14) Firm Net Capability [2/] Summer MW	(15) Status
ADDITIONS/ CHANGES														
FPL														
2026														
Clover Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	5	P
North Orange Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	5	P
Sand Pine Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	5	P
Sea Grape Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	0	12	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2026	Unknown	1,419,500	1,420	1,420	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2026 Changes/Additions Total:	**1,420**	**1,407**	
2027														
Spanish Moss Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	3	4	P
County Line Solar [3/]	1	Charlotte, DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	1	3	P
Hendry Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	3	P
Indrio Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	3	P
Middle Lake Solar [3/]	1	Madison County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	0	5	P
Saddle Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	1	5	P
Tangelo Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	1	3	P
Wood Stork Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	4	4	P
Manatee Upgrade	3	Manatee Country	CC	NG	No	PL	No	-	2nd Q 2027	Unknown	1,346,000	7	43	OP
Catfish Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	3	P
Cocoplum Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	1	3	P
Hardwood Hammock Solar [3/]	1	Walton County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	11	0	P
Joshua Creek Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	1	4	P
Maple Trail Solar [3/]	1	Baker County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	0	5	P
Myakka Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	0	4	P
Pinecone Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	14	0	P
Vernia Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	4	4	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2027	Unknown	819,500	820	656	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
Vandolah	1	Hardee County	CT	NG	No	PL	No	-	2nd Q 2027	Unknown	700,000	700	672	P
											2027 Changes/Additions Total:	**1,570**	**1,407**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Transport Pri.	(8) Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability [2/] Winter MW	(14) Firm Net Capability [2/] Summer MW	(15) Status
ADDITIONS/ CHANGES														
FPL														
2028														
Lansing Smith Retirement	3A	Bay County	CT	LO	--	TK	--	-	May-71	4th Q 2027	40,000	(40)	(32)	P
Beachland Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Bromelaid Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Honeybee Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Inlet Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Sand Gully Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Shores Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Ambersweet Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	1	3	P
Treefrog Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Wabasso Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Waveland Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	74,500	2	4	P
Martin Upgrade	3	Martin County	CC	NG	No	PL	No		2nd Q 2028	Unknown	1,327,000	5	19	OP
Cardinal Solar [3/]	1	Brevard County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
Grapefruit Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
LaBelle Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
Mango Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
Owen Branch Solar [3/]	1	Manatee Country	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	1	5	P
Pine Lily Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	3	4	P
Redroot Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
Shell Creek Solar [3/]	1	Charlotte, DeSoto County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	5	P
Waxweed Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	2	4	P
Wild Lime Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2028	Unknown	74,500	3	4	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	4th Q 2028	Unknown	298,000	8	14	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2028	Unknown	596,000	596	435	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2028 Changes/Additions Total:		**610**	**502**	
2029														
Blanketflower Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	5	P
Dove Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	4	P
Ladybug Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	5	P
Leafcutter Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	5	P
Limpkin Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	4	P
Spoonbill Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	74,500	2	4	P
Caladium Solar [3/]	1	Highlands County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2029	Unknown	74,500	2	4	P
New River Solar [3/]	1	Union County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2029	Unknown	74,500	2	5	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	3rd Q 2029	Unknown	1,788,000	44	92	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2029	Unknown	596,000	596	370	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2029 Changes/Additions Total:	**654**	**483**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability [2/] Winter MW	(14) Firm Net Capability [2/] Summer MW	(15) Status
ADDITIONS/ CHANGES														
FPL														
2030														
Gulf Clean Energy Center Retirement	4	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Gulf Clean Energy Center Retirement	5	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Perdido Retirement	1	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Perdido Retirement	2	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2030	Unknown	596,000	596	310	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2030	Unknown	2,980,000	80	152	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
										2030 Changes/Additions Total:		**523**	**295**	
2031														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2031	Unknown	1,192,000	1,192	620	P
										2031 Changes/Additions Total:		**1,192**	**620**	
2032														
Pea Ridge Retirement	1	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	4th Q 2031	5,000	-	(4)	P
Pea Ridge Retirement	2	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	4th Q 2031	5,000	-	(4)	P
Pea Ridge Retirement	3	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	4th Q 2031	5,000	-	(4)	P
4x0 Martin CT	1	Matin County	CT	NG	-	PL	-	-	1st Q 2032	Unknown	932,000	932	930	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2032	Unknown	596,000	596	250	P
										2032 Changes/Additions Total:		**1,528**	**1,168**	
2033														
4x0 Martin CT	1	Matin County	CT	NG	-	PL	-	-	1st Q 2033	Unknown	932,000	932	930	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2033	Unknown	596,000	596	250	P
										2033 Changes/Additions Total:		**1,528**	**1,180**	
2034														
4x0 Martin CT	1	Matin County	CT	NG	-	PL	-	-	1st Q 2034	Unknown	932,000	932	930	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2034	Unknown	223,500	224	94	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2034	Unknown	1,490,000	40	76	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
										2034 Changes/Additions Total:		**1,196**	**1,086**	
2035														
2x0 Martin CT	1	Matin County	CT	NG	-	PL	-	-	1st Q 2035	Unknown	466,000	596	465	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2035	Unknown	819,500	820	316	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2035	Unknown	1,564,500	42	80	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
										2035 Changes/Additions Total:		**1,458**	**846**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Clover Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	5	MW
c. Winter Firm (AC)	3	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 433 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	28.46% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2026 $/kW):		1,454
Direct Construction Cost ($/kW):		1,380
AFUDC Amount (2026 $/kW):		74.05
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.97 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		1.17

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** North Orange Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	5	MW
c. Winter Firm (AC)	3	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 656 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	27.62% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2026 $/kW):		1,666
Direct Construction Cost ($/kW):		1,580
AFUDC Amount (2026 $/kW):		86
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.97 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		1.17

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sand Pine Solar Energy Center (Calhoun County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 5 MW
- c. Winter Firm (AC) 3 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 719 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	27.14% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years
Total Installed Cost (2026 $/kW):		1,585
Direct Construction Cost ($/kW):		1,508
AFUDC Amount (2026 $/kW):		77
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.97 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		1.15

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sea Grape Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	12	MW
c. Winter Firm (AC)	-	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 564 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	27.66% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2026 $/kW):		1,717
Direct Construction Cost ($/kW):		1,623
AFUDC Amount (2026 $/kW):		94
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.97 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		1.18

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Big Brook Battery Storage (Calhoun County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 6 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,502
Direct Construction Cost ($/kW):		108
AFUDC Amount (2026 $/kW):		3
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cedar Trail Battery Storage (Baker County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	75	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,503
Direct Construction Cost ($/kW):		108
AFUDC Amount (2026 $/kW):		4
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Nature Trail Battery Storage (Baker County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,504
Direct Construction Cost ($/kW):		108
AFUDC Amount (2026 $/kW):		4
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** North Orange Battery Storage (St. Lucie County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,492
Direct Construction Cost ($/kW):		108
AFUDC Amount (2026 $/kW):		3
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Norton Creek Battery Storage (Madison County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	75	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,512
Direct Construction Cost ($/kW):		109
AFUDC Amount (2026 $/kW):		4
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sand Pine Battery Storage (Calhoun County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 14 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,503
Direct Construction Cost ($/kW):		108
AFUDC Amount (2026 $/kW):		4
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Thomas Creek Battery Storage (Nassau County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,520
Direct Construction Cost ($/kW):		110
AFUDC Amount (2026 $/kW):		3
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lansing Smith Battery Storage (Bay County)

(2) **Capacity**
- a. Nameplate (AC) 400.0 MW
- b. Summer Firm (AC)[1/] 400 MW
- c. Winter Firm (AC) 400 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 16 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,446
Direct Construction Cost ($/kW):		555
AFUDC Amount (2026 $/kW):		24
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Clover Battery Storage (St. Lucie County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,426
Direct Construction Cost ($/kW):		103
AFUDC Amount (2026 $/kW):		3
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Fawn Battery Storage (Martin County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 75 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00%
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2026 $/kW):		1,428	
Direct Construction Cost ($/kW):		102	
AFUDC Amount (2026 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28	(First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00	
K Factor:		0.80	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Putnam Battery Storage (Putnam County)

(2) **Capacity**
a. Nameplate (AC) 200 MW
b. Summer Firm (AC)[1/] 200 MW
c. Winter Firm (AC) 200 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 26 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2026 $/kW): 1,300
Direct Construction Cost ($/kW): 250
AFUDC Amount (2026 $/kW): 10
Escalation ($/kW): Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2026 $) 5.28 (First Full Year Operation)
Variable O&M ($/MWH): (2026 $) 0.00
K Factor: 0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sea Grape Battery Storage (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	75	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2025
b. Commercial In-service date:	2026

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2026 $/kW):		1,449	
Direct Construction Cost ($/kW):		104	
AFUDC Amount (2026 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28	(First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00	
K Factor:		0.80	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** White Tail Battery Storage (Martin County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 75 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2025
- b. Commercial In-service date: 2026

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency:	88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years
Total Installed Cost (2026 $/kW):		1,410
Direct Construction Cost ($/kW):		102
AFUDC Amount (2026 $/kW):		3
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	5.28 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		0.80

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Spanish Moss Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	4	MW
c. Winter Firm (AC)	3	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 476 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.97%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,716	
Direct Construction Cost ($/kW):		1,635	
AFUDC Amount (2027 $/kW):		81	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** County Line Solar Energy Center (Charlotte, DeSoto County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	3	MW
c. Winter Firm (AC)	1	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 630 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.44%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,701	
Direct Construction Cost ($/kW):		1,604	
AFUDC Amount (2027 $/kW):		97	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.10	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Hendry Solar Energy Center (Hendry County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	3	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 641 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.12%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,796	
Direct Construction Cost ($/kW):		1,677	
AFUDC Amount (2027 $/kW):		119	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.12	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Indrio Solar Energy Center (St. Lucie County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 3 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2026
- b. Commercial In-service date: 2027

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 400 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	26.14% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2027 $/kW):		1,803
Direct Construction Cost ($/kW):		1,687
AFUDC Amount (2027 $/kW):		116
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36 (First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00
K Factor:		1.13

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Middle Lake Solar Energy Center (Madison County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	5	MW
c. Winter Firm (AC)	-	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 524 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	19.59%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,549	
Direct Construction Cost ($/kW):		1,468	
AFUDC Amount (2027 $/kW):		81	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Saddle Solar Energy Center (DeSoto County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	5	MW
c. Winter Firm (AC)	1	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 647 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	26.95%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,651	
Direct Construction Cost ($/kW):		1,570	
AFUDC Amount (2027 $/kW):		81	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.09	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Tangelo Solar Energy Center (Okeechobee County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	3	MW
c. Winter Firm (AC)	1	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 748 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	26.91%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,706	
Direct Construction Cost ($/kW):		1,592	
AFUDC Amount (2027 $/kW):		113	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Wood Stork Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	4	MW
c. Winter Firm (AC)	4	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 603 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	25.70%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,659	
Direct Construction Cost ($/kW):		1,547	
AFUDC Amount (2027 $/kW):		112	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.13	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Catfish Solar Energy Center (Okeechobee County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	3	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 837 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	26.90%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,753	
Direct Construction Cost ($/kW):		1,651	
AFUDC Amount (2027 $/kW):		103	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.04	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cocoplum Solar Energy Center (Hendry County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC)[1/] 3 MW
- c. Winter Firm (AC) 1 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2026
- b. Commercial In-service date: 2027

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 470 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	26.32% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2027 $/kW):		1,639
Direct Construction Cost ($/kW):		1,538
AFUDC Amount (2027 $/kW):		100
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36 (First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00
K Factor:		1.06

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Hardwood Hammock Solar Energy Center (Walton County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	0	MW
c. Winter Firm (AC)	11	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 750 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	23.49%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,808	
Direct Construction Cost ($/kW):		1,702	
AFUDC Amount (2027 $/kW):		106	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.03	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Joshua Creek Solar Energy Center (DeSoto County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	4	MW
c. Winter Firm (AC)	1	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 621 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.31%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,597	
Direct Construction Cost ($/kW):		1,499	
AFUDC Amount (2027 $/kW):		98	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.06	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Maple Trail Solar Energy Center (Baker County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	5	MW
c. Winter Firm (AC)	0	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 930 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	20.89%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,717	
Direct Construction Cost ($/kW):		1,606	
AFUDC Amount (2027 $/kW):		111	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.06	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Myakka Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	4	MW
c. Winter Firm (AC)	0	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 945 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	24.04%
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,676	
Direct Construction Cost ($/kW):		1,579	
AFUDC Amount (2027 $/kW):		97	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.05	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Pinecone Solar Energy Center (Calhoun County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	-	MW
c. Winter Firm (AC)	14	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 438 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	23.73%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,839	
Direct Construction Cost ($/kW):		1,736	
AFUDC Amount (2027 $/kW):		103	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.05	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Vernia Solar Energy Center (Indian River County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	4	MW
c. Winter Firm (AC)	4	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 402 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	24.88%
Average Net Operating Heat Rate (ANOHR):	Not Applicable
Base Operation 75F,100%	
Average Net Incremental Heat Rate (ANIHR):	Not Applicable
Peak Operation 75F,100%	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		1,511	
Direct Construction Cost ($/kW):		1,423	
AFUDC Amount (2027 $/kW):		89	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	7.36	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		1.05	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Blue Heron Battery Storage (Hendry County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,475	
Direct Construction Cost ($/kW):		106	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Green Pasture Battery Storage (Charlotte County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 15 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR):	Not Applicable
Base Operation 75F,100%	
Average Net Incremental Heat Rate (ANIHR):	Not Applicable
Peak Operation 75F,100%	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,440	
Direct Construction Cost ($/kW):		104	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Orange Blossom Battery Storage (Indian River County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,444	
Direct Construction Cost ($/kW):		104	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sawgrass Battery Storage (Hendry County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 60 MW
- c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2026
- b. Commercial In-service date: 2027

(5) **Fuel**
- a. Primary Fuel Not Applicable
- b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 15 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,445	
Direct Construction Cost ($/kW):		104	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Swamp Cabbage Battery Storage (Hendry County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 15 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,436	
Direct Construction Cost ($/kW):		104	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Terrill Creek Battery Storage (Clay County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	60	MW
c. Winter Firm (AC)	74.5	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR):	Not Applicable
Base Operation 75F,100%	
Average Net Incremental Heat Rate (ANIHR):	Not Applicable
Peak Operation 75F,100%	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,452	
Direct Construction Cost ($/kW):		105	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Indrio Battery Storage (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	60	MW
c. Winter Firm (AC)	74.5	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 2 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,435	
Direct Construction Cost ($/kW):		103	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Maple Trail Battery Storage (Baker County)

(2) **Capacity**

a. Nameplate (AC)	64.5	MW
b. Summer Firm (AC)[1/]	52	MW
c. Winter Firm (AC)	64.5	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,451	
Direct Construction Cost ($/kW):		105	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Monarch ACES Pilot Battery Storage (Martin County)

(2) **Capacity**

a. Nameplate (AC)	10	MW
b. Summer Firm (AC)[1/]	8	MW
c. Winter Firm (AC)	10	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 6 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,429	
Direct Construction Cost ($/kW):		103	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Monarch Battery Storage (Martin County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,429	
Direct Construction Cost ($/kW):		103	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Swallowtail Battery Storage (Walton County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 60 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2027 $/kW): 1,486
Direct Construction Cost ($/kW): 107
AFUDC Amount (2027 $/kW): 4
Escalation ($/kW): Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2027 $) 5.16 (First Full Year Operation)
Variable O&M ($/MWH): (2027 $) 0.00
K Factor: 0.74

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Union Springs Battery Storage (Union County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	60	MW
c. Winter Firm (AC)	75	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2026
b. Commercial In-service date:	2027

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 8 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Round-Trip Efficiency	88.00%
Average Net Operating Heat Rate (ANOHR):	Not Applicable
Base Operation 75F,100%	
Average Net Incremental Heat Rate (ANIHR):	Not Applicable
Peak Operation 75F,100%	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2027 $/kW):		1,451	
Direct Construction Cost ($/kW):		105	
AFUDC Amount (2027 $/kW):		4	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2027 $)	5.16	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	0.00	
K Factor:		0.74	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Beachland Solar Energy Center (Indian River County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 818 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): 28.18% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Bromeliad Solar Energy Center (Collier County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 738 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): 28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Honeybee Solar Energy Center (Collier County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 4 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2027
- b. Commercial In-service date: 2028

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 493 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	28.65% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Inlet Solar Energy Center (Indian River County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	4	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2027
b. Commercial In-service date:	2028

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 461 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.97%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sand Gully Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 647 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	27.52% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Shores Solar Energy Center (Indian River County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 435 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	28.18% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Ambersweet Solar Energy Center (Indian River County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	3	MW
c. Winter Firm (AC)	1	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2027
b. Commercial In-service date:	2028

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 518 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	26.99%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Treefrog Solar Energy Center (Collier County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 663 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): 28.63% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Wabasso Solar Energy Center (Indian River County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	4	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2027
b. Commercial In-service date:	2028

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 450 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	27.99%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Waveland Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 465 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	28.60% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cardinal Solar Energy Center (Brevard County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 591 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	28.17% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Grapefruit Solar Energy Center (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 75.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 554 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	31.17%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** LaBelle Solar Energy Center (Hendry County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 4 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2027
- b. Commercial In-service date: 2028

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 459 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	28.56%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Mango Solar Energy Center (Hendry County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 4 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2027
- b. Commercial In-service date: 2028

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 658 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	31.14%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Owen Branch Solar Energy Center (Manatee County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 5 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2027
- b. Commercial In-service date: 2028

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 635 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	30.98%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Pine Lily Solar Energy Center (St. Lucie County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	4	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2027
b. Commercial In-service date:	2028

(5) **Fuel**

a. Primary Fuel	Solar
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 595 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	30.38%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Redroot Solar Energy Center (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 523 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): 31.24% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Shell Creek Solar Energy Center (Charlotte, DeSoto County)

(2) **Capacity**
- a. Nameplate (AC) 74.5 MW
- b. Summer Firm (AC) 5 MW
- c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2027
- b. Commercial In-service date: 2028

(5) **Fuel**
- a. Primary Fuel: Solar
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 644 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	31.30% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Waxweed Solar Energy Center (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 676 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	31.16% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Wild Lime Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 462 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable
Forced Outage Factor (FOF):	Not Applicable
Equivalent Availability Factor (EAF):	Not Applicable
Resulting Capacity Factor (%):	30.31% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2028 Unsited Solar

(2) **Capacity**
a. Nameplate (AC) 298.0 MW
b. Summer Firm (AC) 14 MW
c. Winter Firm (AC) 8 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Grapefruit Battery Storage (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 4 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Mango Battery Storage (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 4 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Owen Branch Battery Storage (Manatee County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 4 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F, 100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F, 100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Pine Lily Battery Storage (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Redroot Battery Storage (Hendry County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)	55	MW
c. Winter Firm (AC)	76	MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2027
b. Commercial In-service date:	2028

(5) **Fuel**

a. Primary Fuel	Not Applicable
b. Alternate Fuel	Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 4 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	88.00%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2028 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2028 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2028 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2028 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Shell Creek Battery Storage (DeSoto, Charlotte County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 5 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F, 100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F, 100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Waxweed Battery Storage (Hendry County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 4 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F, 100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F, 100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Wild Lime Battery Storage (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 54 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2027
b. Commercial In-service date: 2028

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 3 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: 88.00% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F, 100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F, 100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 20 years
Total Installed Cost (2028 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2028 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2028 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2028 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Blanketflower Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 5 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 484 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Dove Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 618 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Ladybug Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 5 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 410 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Leafcutter Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 5 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 411 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Limpkin Solar Energy Center (Collier County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 472 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Spoonbill Solar Energy Center (Collier County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 484 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Caladium Solar Energy Center (Highlands County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 607 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** New River Solar Energy Center (Union County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 5 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 1,144 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2029 Unsited Solar

(2) **Capacity**
a. Nameplate (AC) 1,788.0 MW
b. Summer Firm (AC) 92 MW
c. Winter Firm (AC) 44 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		35 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Blankketflower Battery Storage (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 46 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 7 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F, 100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F, 100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 20 years
Total Installed Cost (2029 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2029 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2029 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2029 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Ladybug Battery Storage (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 46 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 8 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Leafcutter Battery Storage (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 46 MW
c. Winter Firm (AC) 75 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** 7 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F, 100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F, 100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2029 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 372.5 MW
b. Summer Firm (AC) 231 MW
c. Winter Firm (AC) 373 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2029 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2029 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2029 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2029 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2030 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 596.0 MW
b. Summer Firm (AC) 310 MW
c. Winter Firm (AC) 596 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2029
b. Commercial In-service date: 2030

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data** *

Book Life (Years):		20 years	
Total Installed Cost (2030 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2030 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2030 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2030 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2030 Unsited Solar

(2) **Capacity**
a. Nameplate (AC) 2,980.0 MW
b. Summer Firm (AC) 152 MW
c. Winter Firm (AC) 80 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2029
b. Commercial In-service date: 2030

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2030 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2030 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2030 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2030 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2031 Unsited Battery Storage

(2) **Capacity**
- a. Nameplate (AC) 1,192.0 MW
- b. Summer Firm (AC) 624 MW
- c. Winter Firm (AC) 1,192 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2030
- b. Commercial In-service date: 2031

(5) **Fuel**
- a. Primary Fuel: Not Applicable
- b. Alternate Fuel: Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2031 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2031 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2031 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2031 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2032 4x0 Martin CTs

(2) **Capacity**
a. Nameplate (AC) 932.0 MW
b. Summer Firm (AC) 930 MW
c. Winter Firm (AC) 932 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2032

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 50 years
Total Installed Cost (2032 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2032 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2032 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2032 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2032 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 596.0 MW
b. Summer Firm (AC) 250 MW
c. Winter Firm (AC) 596 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2031
b. Commercial In-service date: 2032

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2032 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2032 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2032 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2032 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2033 4x0 Martin CTs

(2) **Capacity**
a. Nameplate (AC) 932.0 MW
b. Summer Firm (AC) 930 MW
c. Winter Firm (AC) 932 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2029
b. Commercial In-service date: 2033

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		50 years	
Total Installed Cost (2033 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2033 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2033 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2033 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2033 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 596.0 MW
b. Summer Firm (AC) 250 MW
c. Winter Firm (AC) 596 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2032
b. Commercial In-service date: 2033

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2033 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2033 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2033 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2033 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2034 4x0 Martin CTs

(2) **Capacity**
a. Nameplate (AC) 932.0 MW
b. Summer Firm (AC) 930 MW
c. Winter Firm (AC) 932 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2030
b. Commercial In-service date: 2034

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		50 years	
Total Installed Cost (2034 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2034 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2034 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2034 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2034 4x0 Martin CTs

(2) **Capacity**
a. Nameplate (AC) 932.0 MW
b. Summer Firm (AC) 930 MW
c. Winter Firm (AC) 932 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2030
b. Commercial In-service date: 2034

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		50 years	
Total Installed Cost (2034 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2034 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2034 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2034 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2034 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 223.5 MW
b. Summer Firm (AC) 94 MW
c. Winter Firm (AC) 223.5 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2033
b. Commercial In-service date: 2034

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Round-Trip Efficiency: TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 20 years
Total Installed Cost (2034 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2034 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2034 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2034 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2035 2x0 Martin CTs

(2) **Capacity**
a. Nameplate (AC) 596.0 MW
b. Summer Firm (AC) 465 MW
c. Winter Firm (AC) 596 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2031
b. Commercial In-service date: 2035

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		50 years	
Total Installed Cost (2035 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2035 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2035 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2035 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2035 Unsited Solar

(2) **Capacity**
a. Nameplate (AC) 1,564.5 MW
b. Summer Firm (AC) 80 MW
c. Winter Firm (AC) 42 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2034
b. Commercial In-service date: 2035

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not Applicable
Forced Outage Factor (FOF): Not Applicable
Equivalent Availability Factor (EAF): Not Applicable
Resulting Capacity Factor (%): TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not Applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not Applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2035 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2035 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2035 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2035 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** 2035 Unsited Battery Storage

(2) **Capacity**
a. Nameplate (AC) 819.5 MW
b. Summer Firm (AC) 316 MW
c. Winter Firm (AC) 819.5 MW

(3) **Technology Type:** Battery Storage

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2034
b. Commercial In-service date: 2035

(5) **Fuel**
a. Primary Fuel Not Applicable
b. Alternate Fuel Not Applicable

(6) **Air Pollution and Control Strategy:** Not Applicable

(7) **Cooling Method:** Not Applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not Applicable	
Forced Outage Factor (FOF):	Not Applicable	
Equivalent Availability Factor (EAF):	Not Applicable	
Round-Trip Efficiency:	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not Applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not Applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2035 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2035 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2035 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2035 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Clover Solar Energy Center (St. Lucie County)

The Clover Solar Energy Center will require extending a transmission line from the new Sunbreak Substation approximately 2.0 miles to connect the new Clover Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak Substation to the new Clover Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	Approximately 2 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Clover Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Sea Grape Solar Energy Center (St. Lucie County)

The Sea Grape Solar Energy Center will require bifurcating the new FPL Sunbreak - Morrow 230 kV transmission line approximately 0.0 miles to connect a new Muscadine substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Morrow 230 kV transmission line to new Muscadine Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Muscadine Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

North Orange Solar Energy Center (St. Lucie County)

The North Orange Solar Energy Center will require bifurcating the new FPL Sunbreak - Morrow 230 kV transmission line approximately 0.0 miles to connect a new Apricot substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Morrow 230 kV transmission line to new Apricot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Apricot Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sand Pine Solar Energy Center (Calhoun County)

The Sand Pine Solar Energy Center will require extending the transmission bus at Quincy Substation approximately 0.0 miles to connect a new Chinkapin substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Quincy Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Chinkapin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Big Brook Battery Energy Storage System Center (Calhoun County)

The Big Brook Battery Energy Storage Center will be connected to the transmission bus at Song Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Song Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Song Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sand Pine Battery Energy Storage System Center (Calhoun County)

The Sand Pine Battery Energy Storage Center will be connected to the transmission bus at Quincy Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Quincy Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Chinkapin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

North Orange Battery Energy Storage System Center (St. Lucie County)

The North Orange Battery Energy Storage Center will be connected to the transmission bus at Apricot Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Apricot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Apricot Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Norton Creek Battery Energy Storage System Center (Madison County)

The Norton Creek Battery Energy Storage Center will be connected to the transmission bus at Bandit Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Bandit Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	161 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Bandit Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Thomas Creek Battery Energy Storage System Center (Nassau County)

The Thomas Creek Battery Energy Storage Center will be connected to the transmission bus at Thomas Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Thomas Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Thomas Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Cedar Trail Battery Energy Storage System Center (Baker County)

The Cedar Trail Battery Energy Storage Center will be connected to the transmission bus at Deodar Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Deodar Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Deodar Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Nature Trail Battery Energy Storage System Center (Baker County)

The Nature Trail Battery Energy Storage Center will be connected to the transmission bus at Harvey Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Harvey Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Harvey Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Lansing Smith Battery Energy Storage System Center (Bay County)

The Lansing Smith Battery Energy Storage System Center will be connected to the transmission bus at Lansing Smith Switchyard approximately 0.26 miles to a new Parakeet substation and connect the BESS system.

(1) Point of Origin and Termination:	Parakeet substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.26 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Parakeet substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Putnam Battery Energy Storage System Center (Putnam County)

The Putnam Battery Energy Storage System Center will be connected to the transmission bus at Putnam Switchyard approximately 0.3 miles to a new Putnam BESS U1 substation and connect the BESS system.

(1) Point of Origin and Termination:	Putnam BESS U1 substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.3 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Putnam BESS U1 substation
(9) Participation with Other Utilities:	None
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Clover Battery Energy Storage System Center (St. Lucie County)

The Clover Battery Energy Storage System Center will be connected to the transmission bus at Clover Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Clover Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Clover Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sea Grape Battery Energy Storage System Center (St. Lucie County)

The Sea Grape Battery Energy Storage System Center will be connected to the transmission bus at Muscadine Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Muscadine Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Muscadine Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

White Tail Battery Energy Storage System Center (Martin County)

The White Tail Battery Energy Storage System Center will be connected to the transmission bus at Strawberry Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Strawberry Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Strawberry Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fawn Battery Energy Storage System Center (Martin County)

The Fawn Battery Energy Storage System Center will be connected to the transmission bus at Fawn Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Fawn Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Fawn Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Indrio Solar Energy Center (St. Lucie County)

The Indrio Solar Energy Center will require bifurcating the new FPL Sunbreak - Heritage 230 kV transmission line approximately 0.0 miles to connect a new Estuary substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Heritage 230 kV transmission line to new Estuary Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Estuary Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Tangelo Solar Energy Center (Okeechobee County)

The Tangelo Solar Energy Center will require extending the transmission bus at Clementine Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Clementine Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Clementine Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Wood Stork Solar Energy Center (St. Lucie County)

The Wood Stork Solar Energy Center will require extending the transmission bus at Liberty Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Liberty Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Liberty Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Hendry Solar Energy Center (Hendry County)

The Hendry Solar Energy Center will require extending the transmission bus at Ghost Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Ghost Substation
(2) Number of Lines:	0
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ghost Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Middle Lake Solar Energy Center (Madison County)

The Middle Lake Solar Energy Center will require extending the transmission bus at future Bandit Substation approximately 0.0 miles to a new Sound substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sound Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	161 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Sound Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Spanish Moss Solar Energy Center (St. Lucie County)

The Spanish Moss Solar Energy Center will require extending the transmission bus at Apricot Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Apricot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Apricot Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

County Line Solar Energy Center (DeSoto County)

The County Line Solar Energy Center will require extending the transmission bus at Notts Substation approximately 0.0 miles to connect a new Medieval substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Medieval Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Medieval Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Saddle Solar Energy Center (DeSoto County)

The Saddle Solar Energy Center will require extending the transmission bus at Ponna Substation approximately 0.0 miles to a new Cheriot substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Cheriot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Pignut Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Swamp Cabbage Battery Energy Storage System Center (Hendry County)

The Swamp Cabbage Battery Energy Storage Center will be connected to the transmission bus at Swamp Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Swamp Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Swamp Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Green Pasture Battery Energy Storage System Center (Charlotte County)

The Green Pasture Battery Energy Storage Center will be connected to the transmission bus at Zoysia Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Zoysia Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Zoysia Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Blue Heron Battery Energy Storage System Center (Hendry County)

The Blue Heron Battery Energy Storage Center will be connected to the transmission bus at Citron Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Citron Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	138 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Citron Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Sawgrass Battery Energy Storage System Center (Hendry County)

The Sawgrass Battery Energy Storage Center will be connected to the transmission bus at Ghost Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Ghost Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ghost Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Terrill Creek Battery Energy Storage System Center (Clay County)

The Terrill Creek Battery Energy Storage Center will be connected to the transmission bus at Terrill Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Terrill Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Terrill Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Orange Blossom Battery Energy Storage System Center (Indian River County)

The Sawgrass Battery Energy Storage Center will be connected to the transmission bus at Finca Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Finca Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Finca Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Hardwood Hammock Solar Energy Center (Walton County)

The Hardwood Hammock Solar Energy Center will require extending the transmission bus at Quail Substation approximately 0.0 miles to connect a new Pignut substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Quail Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Pignut Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Maple Trail Solar Energy Center (Baker County)

The Maple Trail Solar Energy Center will require extending the transmission bus at Deodar Substation approximately 0.0 miles to connect a new Maple substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Maple Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Maple Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Maple Trail Battery Energy Storage System Center (Baker County)

The Maple Trail Battery Energy Storage Center will be connected to the transmission bus at Deodar Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Deodar Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Deodar Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Indrio Battery Energy Storage System Center (St. Lucie County)

The Indrio Battery Energy Storage Center will be connected to the transmission bus at Estuary Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Estuary Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Estuary Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Monarch Battery Energy Storage System Center (Martin County)

The Monarch Battery Energy Storage Center will be connected to the transmission bus at Gopher Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Gopher Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Gopher Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Monarch ACES Battery Energy Storage System Center Pilot (Martin County)

The Monarch ACES Battery Energy Storage Center Pilot will be connected to the transmission bus at Gopher Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Gopher Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Gopher Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Swallowtail Battery Energy Storage System Center (Walton County)

The Swallowtail Battery Energy Storage Center will be connected to the transmission bus at Swallowtail Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Swallowtail Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Swallowtail Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Union Springs Battery Energy Storage System Center (Union County)

The Union Springs Battery Energy Storage Center will be connected to the transmission bus at Plum Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Plum Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Plum Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Catfish Solar Energy Center (Okeechobee County)

The Catfish Solar Energy Center will require extending the transmission bus at Pyrite Substation approximately 0.0 miles to connect a new Catfish substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Catfish Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Catfish Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cocoplum Solar Energy Center (Hendry County)

The Cocoplum Solar Energy Center will require extending the transmission bus at Witt Substation approximately 0.0 miles to connect a new Mulberry substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Mulberry Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Mulberry Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Pinecone Solar Energy Center (Calhoun County)

The Pinecone Solar Energy Center will require extending the transmission bus at Chinkapin Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Chinkapin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Chinkapin Substation
(9) Participation with Other Utilities:	None
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Myakka Solar Energy Center (Manatee County)

The Mayakka Solar Energy Center will require extending the transmission bus at Lemur Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Lemur Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lemur Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Joshua Creek Solar Energy Center (DeSoto County)

The Joshua Creek Solar Energy Center will require extending a transmission bus at Stallion Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Stallion Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Stallion Substation
(9) Participation with Other Utilities:	None
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vernia Solar Energy Center (Indian River County)

The Vernia Solar Energy Center will require bifurcating the FPL Sunbreak - Glint 230 kV transmission line approximately 0.0 miles to connect a new Vernia substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Vernia
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Vernia
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ambersweet Solar Energy Center (Indian River County)

The Ambersweet Solar Energy Center will require extending the transmission bus at Vernia Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Ambersweet Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ambersweet Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Waveland Solar Energy Center (St. Lucie County)

The Waveland Solar Energy Center will require bifurcating the new FPL Sunbreak - Heritage 230 kV transmission line approximately 0.0 miles to connect a new Waveland substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Waveland Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Waveland Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Inlet Solar Energy Center (Indian River County)

The Inlet Solar Energy Center will require bifurcating the new FPL Waveland - Heritage 230 kV transmission line approximately 0.0 miles to connect a new Lumia substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Lumia Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lumia Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Beachland Solar Energy Center (Indian River County)

The Beachland Solar Energy Center will require extending the transmission bus at Finance Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Finance Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Finance Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Wabasso Solar Energy Center (Indian River County)

The Wabasso Solar Energy Center will require extending the transmission bus at Finca Substation line approximately 4.5 miles to connect a new Finance substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Finance Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	4.5 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Finance Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Shores Solar Energy Center (Indian River County)

The Shores Solar Energy Center will require extending the transmission bus at Finance Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Finance Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Finance Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Treefrog Solar Energy Center (Collier County)

The Treefrog Solar Energy Center will require extending the transmission bus at Boardwalk Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Honeybee Solar Energy Center (Collier County)

The Honeybee Solar Energy Center will require extending the transmission bus at Boardwalk Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Bromeliad Solar Energy Center (Collier County)

The Bromeliad Solar Energy Center will require extending the transmission bus at Boardwalk Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sand Gully Solar Energy Center (DeSoto County)

The Sand Gully Solar Energy Center will require extending the transmission bus at Stallion Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Stallion Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Stallion Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Pine Lily Solar Energy Center (St. Lucie County)

The Pine Lily Solar Energy Center will require bifurcating the Glint-Seville 230kV transmission line approximately 0.0 miles to connect a new Lily substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Lily Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lily Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Pine Lily Battery Energy Storage System Center (St. Lucie County)

The Pine Lily Battery Energy Storage Center will be connected to the transmission bus at Lily Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Lily Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lily Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Wild Lime Solar Energy Center (St. Lucie County)

The Wild Lime Solar Energy Center will require extending the transmission bus at Lilly Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Lilly Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lilly Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Wild Lime Battery Energy Storage System Center (St. Lucie County)

The Wild Lime Battery Energy Storage Center will be connected to the transmission bus at Lily Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Lily Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lily Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Waxweed Solar Energy Center (Hendry County)

The Waxweed Solar Energy Center will require bifurcating the Puma-Keri 230kV transmission line approximately 0.0 miles to connect a new Waxweed substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Waxweed Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Waxweed Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Waxweed Battery Energy Storage System Center (Hendry County)

The Waxweed Battery Energy Storage Center will be connected to the transmission bus at Waxweed Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Waxweed Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Waxweed Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Owen Branch Solar Energy Center (Manatee County)

The Owen Branch Solar Energy Center will require extending the transmission bus at Flatford Substation line approximately 0.0 miles to connect a new Owen substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Owen Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Owen Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Owen Branch Battery Energy Storage System Center (Manatee County)

The Owen Branch Battery Energy Storage Center will be connected to the transmission bus at Owen Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Owen Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Owen Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Shell Creek Solar Energy Center (DeSoto County)

The Shell Creek Solar Energy Center will require extending the transmission bus at Notts Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Notts Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Notts Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Shell Creek Battery Energy Storage System Center (Desoto County)

The Shell Creek Battery Energy Storage Center will be connected to the transmission bus at Notts Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Notts Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Notts Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

LaBelle Solar Energy Center (Hendry County)

The Labelle Solar Energy Center will require extending the transmission bus at Swamp Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Swamp Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Swamp Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cardinal Solar Energy Center (Brevard County)

The Cardinal Solar Energy Center will require extending the transmission bus at Goodwin Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Goodwin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Goodwin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Redroot Solar Energy Center (Hendry County)

The Redroot Solar Energy Center will require extending the transmission bus at Waxweed Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Waxweed Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Waxweed Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Redroot Battery Energy Storage System Center (Hendry County)

The Redroot Battery Energy Storage Center will be connected to the transmission bus at Waxweed Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Waxweed Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Waxweed Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Mango Solar Energy Center (Hendry County)

The Mango Solar Energy Center will require bifurcating the Puma-Keri 230kV transmission line approximately 0.0 miles to connect a new Towhee substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Towhee Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Towhee Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Mango Battery Energy Storage System Center (Hendry County)

The Mango Battery Energy Storage Center will be connected to the transmission bus at Towhee Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Towhee Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Towhee Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Grapefruit Solar Energy Center (Hendry County)

The Grapefruit Solar Energy Center will require extending the transmission bus at Towhee Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Towhee Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Towhee Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Grapefruit Battery Energy Storage System Center (Hendry County)

The Grapefruit Battery Energy Storage Center will be connected to the transmission bus at Towhee Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Towhee Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Towhee Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ladybug Solar Energy Center (Desoto County)

The Ladybug Solar Energy Center will require extending the transmission bus at Stallion Substation approximately 8.0 miles to a new Tern substation to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	8 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Ladybug Battery Energy Storage System Center (Desoto County)

The Ladybug Battery Energy Storage Center will be connected to the transmission bus at Tern Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Leafcutter Solar Energy Center (DeSoto County)

The Grapefruit Solar Energy Center will require extending the transmission bus at Tern Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Leafcutter Battery Energy Storage System Center (Desoto County)

The Leafcutter Battery Energy Storage Center will be connected to the transmission bus at Tern Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Blanketflower Solar Energy Center (DeSoto County)

The Blanketflower Solar Energy Center will require will require extending the transmission bus at Tern Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Blanketflower Battery Energy Storage System Center (Desoto County)

The Blanketflower Battery Energy Storage Center will be connected to the transmission bus at Tern Substation approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Tern Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tern Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Dove Solar Energy Center (Desoto County)

The Dove Solar Energy Center will require bifurcating the Doorfield-Avon 230kV transmission line approximately 0.0 miles to connect a new Dove substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Dove Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Dove Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Spoonbill Solar Energy Center (Collier County)

The Spoonbill Solar Energy Center will require extending the transmission bus at Boardwalk Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Limkin Solar Energy Center (Collier County)

The Limkin Solar Energy Center will require extending the transmission bus at Boardwalk Substation line approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

New River Solar Energy Center (Union County)

The New River Solar Energy Center will require bifurcating the Lake Butler-Plum 115kV transmission line approximately 0.0 miles to connect a new Damson substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Damson Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Damson Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Caladium Solar Energy Center (Highlands County)

The Caladium Solar Energy Center will require bifurcating the Avon-Waterway 230kV transmission line approximately 0.0 miles to connect a new Condor substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Condor Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2028 End date: 2029
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Condor Substation
(9) Participation with Other Utilities:	None

Schedule 11.1: FPL

Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type
Actuals for the Year 2024

	(1)	(2)	(3)	(4)	(5)	(8)	(9)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh [2]**	**%**
(1)	Coal	215	0.6%	215	0.6%	479	0.3%
(2)	Nuclear	3,502	9.4%	3,588	9.4%	29,384	20.0%
(3)	Residual	0	0.0%	0	0.0%	0	0.0%
(4)	Distillate	134	0.4%	163	0.4%	56	0.0%
(5)	Natural Gas	24,169	65.2%	25,373	66.1%	99,427	67.5%
(6)	Landfill Gas	3	0.0%	3	0.0%		
(7)	Solar (Firm & Non-Firm)	7,932	21.4%	7,932	20.7%	16,738	11.4%
(8)	Battery	991	2.7%	991	2.6%	-	-
(9)	***FPL Existing Units Total [1] :***	***36,946***	**99.7%**	***38,265***	**99.7%**	***146,084***	***99.2%***
(10)	Renewables (Purchases)- Firm	129	0.3%	109	0.3%	1,838	1.2%
(11)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	1,230	0.8%
(12)	***Renewable Total:***	**129**	**0.0**	**109**	**0.0**	**3,069**	**2.1%**
(13)	***Purchases Other / (Sales) :***	**0.0**	**0.0%**	**0.0**	**0.0%**	**(1,881)**	**-1.3%**
(14)	***Total:***	***37,075***	***100.0%***	***38,374***	***100.0%***	***147,271***	***100.0%***

Note:

(1) FPL Existing Units Total values on row (9), columns (2) and (4) match the Total Nameplate System Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (14), column (8), matches Schedule 6.1 value for 2025.

(3) Information on projected renewable capacity and energy is available in Schedule 6.1, Schedule 8, and Schedule 9.

Schedule 11.2: FPL
Existing Non-Firm Self-Service Renewable Generation Facilities
Actuals for the Year 2025 [1/]

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh) [2/]	Annual Energy Purchased from FPL (MWh) [3/]	Annual Energy Sold to FPL - Total (MWh) [4/]	Projected Annual Energy Used by Customers [5/]
Customer-Owned Renewable Generation (0 kW to 10 kW)	488.93	626,830	584,912	258,471	953,271
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	955.53	1,497,279	993,468	500,492	1,990,255
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	85.97	144,646	2,086,699	24,119	2,207,226
Totals	1,530.43	2,268,755	3,665,079	783,082	5,150,752

1/ There were approximately 133,737 customers with renewable generation facilities interconnected with FPL on December 31, 2025.
2/ The Projected Annual Output value is based on NREL's PV Watts 1 program and uses the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
3/ The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2025.
4/ The Annual Energy Sold to FPL - Total is an actual value from FPL's metered data for 2025. These are the total MWh that were "overproduced" by the customer each month throughout 2025.
5/ The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL - Total).

Schedule 11.3: FPL

Renewable Capacity and Energy Projections, 2026-2035

Capacity Projections (Nameplate MW)

Renewable Type:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Solar (Firm & Non-Firm)	8,826	10,018	11,806	14,190	17,170	17,170	17,170	17,170	18,660	20,225
Renewables (Purchases)- Firm	420	417	417	417	417	417	362	272	272	272
Renewables (Purchases)- Non-Firm	120	120	120	120	120	120	120	120	120	120
Customer-Owned Renewable Generation	1,135	1,250	1,382	1,534	1,701	1,886	2,091	2,319	2,572	2,852

Energy Projections (GWh)

Renewable Type:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Solar (Firm & Non-Firm)	19,382	21,395	24,845	29,886	39,932	39,793	39,747	39,502	43,055	46,767
Renewables (Purchases)- Firm	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838
Renewables (Purchases)- Non-Firm	*	*	*	*	*	*	*	*	*	*
Customer-Owned Renewable Generation	1,956	2,148	2,364	2,613	2,892	3,200	3,542	3,922	4,342	4,809

* FPL does not project non-firm energy as it is dependent on outside factors. Energy production from FPL's 120 MW of solar PPAs is included in the "Solar" entry

(This page is intentionally left blank.)

CHAPTER IV

Environmental and Land Use Information

(This page is intentionally left blank.)

IV. Environmental and Land Use Information

IV.A. Protection of the Environment

Reliable and low-cost energy is the lifeblood of Florida's growing population, expanding economy, and environmental resource restoration and management. Through its commitment to environmental excellence, FPL is helping to solve Florida's energy challenges sustainably and responsibly, while maintaining service reliability and keeping customer rates as low as possible. With one of the cleanest, most efficient power-generation fleets in the nation, FPL has reduced its use of heavy oil, including foreign oil, by approximately 99.99 percent – from approximately 41 million barrels annually in 2001 to less than 0.1 million barrels in 2025. FPL also has one of the lowest emissions profiles among U.S. utilities. In 2025, CO_2 rates for FPL were 23% lower, then the U.S. electric power sector average. At the end of 2025, FPL had approximately 7,932 MW of solar generation capability on its system (which consists entirely of universal solar), making FPL the largest producer of solar energy-generated electricity in Florida. In addition, FPL also has renewable energy purchase agreements for approximately 120 MW of universal solar generation.

This 2026 Site Plan for FPL presents a resource plan which shows a significant amount of additional solar. FPL's system is projected to have approximately 20,225 MW of solar by the end of the ten-year reporting period (2035) for this Site Plan.

FPL maintains its commitment to environmental stewardship through proactive collaboration with communities and organizations working to preserve Florida's unique habitat and natural resources. The many projects and programs in which FPL actively participates includes the creation and management of the Manatee Lagoon – An FPL Eco-Discovery Center®, a busy and thriving center which welcomes close to 200,000 visitors annually. In addition, the Everglades Mitigation Bank, Solar Stewardship program, and the Turkey Point Crocodile Management Program are excellent examples of FPL's stewardship. FPL has invested more than $160 million to construct and retrofit more than 185,000 poles to make them more bird-friendly, reducing avian risk and improving service reliability to our customers. To identify and proactively address high-risk distribution structures, FPL created the energy industry's first avian risk assessment model. In 2022, FPL updated the avian risk assessment model as part of integrating Gulf Power into FPL's Avian Protection Program, and to further enhance avian assessment for eagles and wood storks, and protection processes.

In 2017, FPL launched its Solar Stewardship program in partnership with Audubon Florida. For the majority of its solar sites, FPL works with Audubon Florida and other local organizations to craft

site-specific habitat enhancement and preservation plans focused on providing habitat opportunities for birds, pollinators and other wildlife. FPL accomplishes this through a variety of prescriptive methodologies, including but not limited to:

- Restoring hydrology to wetlands;
- Increasing biodiversity through the use of appropriate native plant species;
- Removing invasive species and implementing procedures to prevent regrowth;
- Incorporating pollinator species into ground covers; and
- Installing artificial perches, nest boxes, and platforms for wildlife use.

FPL continues to work with regulatory agencies, municipalities, academic institutions, and community groups to address local or regional environmental objectives.

IV.B Environmental Organization Contributions

In 2025, FPL, through its charitable arm, the NextEra Energy Foundation, supported a broad base of environmental organizations with donations focused on education, conservation, and research. Those organizations include Fish & Wildlife Foundation of Florida, Florida State Parks Foundation, Inwater Research Group, Florida Defenders of Wildlife, Audubon (state and local chapters), Everglades Foundation, Loggerhead Marinelife Center, Clearwater Marine Aquarium Research Institute, Mote Marine Laboratory and Aquarium, Ocean Research & Conservation Association, Conservancy of Southwest Florida, Brevard Zoo, Central Florida Zoo, Palm Beach Zoo, Emerald & Forgotten Coast Adventures, the Manatee Rescue & Rehabilitation Partnership, and the Jupiter Narrows Conservation Alliance. FPL employees serve in board and leadership positions for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes Grassy Waters Conservancy, Loggerhead Marinelife Center, Marine Resources Council, Busch Wildlife Sanctuary, Everglades Foundation, Florida Oceanographic Society, and Audubon Florida. FPL employees also invest volunteer hours supporting conservation partners in maintaining, restoring, and protecting waters, wetlands, forests, beaches, parks, historic sites, and wildlife.

IV.C Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental conservation through the facilitation of energy efficiency, environmental awareness, and through public education. Some of FPL's 2025 environmental outreach activities are summarized in Table IV.C.1.

Table IV.C.1: 2025 FPL Environmental Outreach Activities

Activity	Approximate Count (#)
Visitors to Manatee Lagoon - An FPL Eco-Discovery Center®	**200,000**
Number of website visits to Manatee Lagoon website, visitmanateelagoon.com	860,000 780,000
Number of website visits to NextEra and FPL's Environmental & Corporate Sustainability Websites	**22,000**
Visitors to Manatee Park, Ft. Myers	**200,000**
Home Energy Surveys	Field Surveys: 18,000 Phone Surveys: 16,000 Online Surveys: 72,000 **Total: 106,000**

IV.D Environmental Policy

FPL and its parent company, NextEra Energy, are committed to remaining an industry leader in environmental conservation and stewardship, not only because it makes business sense, but because it is the right thing to do. This commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives its business planning, operations, and daily work.

In accordance with commitments to environmental compliance, conservation, and stewardship, FPL and NextEra Energy endeavor to:

Comply:

- Site, design, permit, construct, operate, and maintain our facilities in an environmentally responsible manner;
- Comply with all applicable environmental laws, regulations, and permits;
- Proactively identify environmental risks and take action to mitigate those risks;

- Participate in legislative and regulatory processes to ensure that environmental laws, regulations, guidance documents, and policies are technically sound and economically feasible; and
- Pursue opportunities to exceed environmental standards.

Conserve:

- Promote the efficient use of energy, both within our company and in our communities;
- Prevent pollution, minimize waste, and conserve natural resources;
- Promote sustainability in our daily actions and project planning, where applicable;
- Endeavor to avoid, to the extent practicable, impacts to habitat, wildlife, jurisdictional waters, and cultural resources; minimize, and/or mitigate unavoidable impacts to such resources; and
- Lead with innovative solutions that synthesize environmental conservation and prudent operations.

Communicate:

- Communicate this policy annually to all employees, and maintain on internal website for easy reference;
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence;
- Maintain honest and open dialogue with stakeholders, including federal, state, and local agencies on environmental goals, processes, and performance; and
- Highlight policy with external stakeholders and provide accurate reporting on environmental impacts (sustainability reporting).

Continuously Improve:

- Establish, monitor, and report progress toward environmental targets;
- Review and update this policy on a regular basis;
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices;
- Perform self-assessments of our operating facilities through the internal environmental audit program to ensure compliance, share best practices, and incorporate learnings across the fleet; and
- Maintain strong strategic vision to continuously seek innovative win-win solutions to complex environmental issues

FPL complies with all environmental laws, regulations, and permit requirements, and designs, constructs, and operates its facilities in an environmentally sound and responsible manner. FPL also responds immediately and effectively to any known environmental hazards or non-compliance situations. The commitment to the environment does not end there. FPL proactively pursues opportunities to perform better than current environmental standards require, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout their operations and day-to-day work activities. FPL encourages cost-effective, efficient uses of energy, both within the Company and with its customers. These actions are just a few examples of how FPL is committed to the environment.

To ensure FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program. Through this program, FPL conducts periodic environmental self-evaluations to verify that its operations comply with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.E Environmental Management

To successfully implement this Environmental Policy, FPL has developed a robust Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program, which is described in section IV.F below. Other system components include: executive management support and commitment, dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.F Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities designed to evaluate environmental performance, verify compliance with corporate policy and legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing

environmental assurance is an environmental audit. An environmental audit is defined as a management tool comprised of a systematic, documented, risk-based, and objective evaluation of the performance of the organization and its specific management systems and equipment designed to protect the environment. An environmental audit's primary objective is to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and corporate policies. In addition to FPL facility audits, through the Environmental Assurance Program, audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations are performed. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

In addition to periodic environmental audits, NextEra Energy's Environmental Construction Compliance Assurance Program provides routine onsite inspections during construction and site-specific environmental training to everyone anticipated to be onsite during construction. Similar to an environmental audit, these inspections are performed to ensure compliance with the requirements of environmental permits, licenses, and corporate policies during the construction phase. Additionally, the Construction Compliance Assurance Program has integrated remote satellite and drone monitoring technology to broaden its inspection capabilities and increase the frequency of onsite observations.

FPL has also implemented a Corporate Environmental Governance System in which quarterly reviews are performed of each business unit deemed to have potential for significant environmental exposure. Quarterly reviews evaluate operations for potential environmental risks and consistency with the Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress changes since the most recent review.

IV.G Preferred and Potential Sites

Based upon projection of future resource needs and analyses of viable resource options, 94 Preferred Sites and 38 Potential Sites have been identified for adding future generation. Some of these sites currently have existing generation. Preferred Sites are those locations where significant reviews have taken place and action has either been taken, action is committed, or it is likely that action will be taken to site new generation. Potential Sites are those with attributes that would support the siting of generation and are under consideration as a location for future generation. The identification of a Potential Site does not necessarily indicate that a definitive decision has been made to pursue new generation, generation expansion, or modernization, nor does this

designation necessarily indicate that the size or technology of a generating resource has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.G.1 Preferred Sites

For the 2026 Ten-Year Site Plan, 94 Preferred Sites have been identified. These include new sites for the development of solar generation facilities, battery storage facilities, nuclear generation, and fossil generation. Sites for numerous solar and battery energy storage site additions in 2027, 2028, and 2029 have been selected, and these sites are described in this section. Solar sites are considered ideal locations for battery storage facilities, so many of the planned battery storage facilities in this Site Plan are dual sited at existing or planned solar sites. Potential sites for possible 2029 and beyond solar additions are discussed later in the Potential Site section.

These 94 Preferred Sites are listed in Table IV.G.1 below, and information about each site is presented in the Appendix at the end of this document. The sites are presented in general chronological order of when resources are projected to be added to the FPL system. The topographical features of each site, land use, and facility layout figures are provided in maps that also appear in the Appendix at the end of this document. It is important to note that while most of the battery storage facilities are located on or are contiguous with their respective solar site, that is not the case for all of them. For several of the Battery Energy Storage System (BESS) Centers, the maps show the BESS facility located outside the solar site's boundary. These battery storage facilities are being constructed near the already existing substation for optimal interconnection and grid access.

Table IV.G.1: List of FPL Preferred Sites			
	Site Name	**County**	**Technology**
1	Big Brook Solar Energy Center	Calhoun County	Solar
2	Boardwalk Solar Energy Center	Collier County	Solar
3	Flatford Solar Energy Center	Manatee County	Solar
4	Goldenrod Solar Energy Center	Collier County	Solar
5	Mallard Solar Energy Center	Brevard County	Solar
6	Mare Branch Solar Energy Center	DeSoto County	Solar
7	Price Creek Solar Energy Center	Columbia County	Solar
8	Swamp Cabbage Solar Energy Center	Hendry County	Solar
9	Clover Solar Energy Center	St. Lucie County	Solar
10	North Orange Solar Energy Center	St. Lucie County	Solar
11	Sand Pine Solar Energy Center	Calhoun County	Solar
12	Sea Grape Solar Energy Center	St. Lucie County	Solar
13	Big Brook Battery Storage	Calhoun County	Battery Storage
14	Cedar Trail Battery Storage	Baker County	Battery Storage
15	Nature Trail Battery Storage	Baker County	Battery Storage
16	North Orange Battery Storage	St. Lucie County	Battery Storage
17	Norton Creek Battery Storage	Madison County	Battery Storage
18	Sand Pine Battery Storage	Calhoun County	Battery Storage
19	Thomas Creek Battery Storage	Nassau County	Battery Storage
20	Lansing Smith Battery Storage	Bay County	Battery Storage
21	Clover Battery Storage	St. Lucie County	Battery Storage
22	Fawn Battery Storage	Martin County	Battery Storage
23	Putnam Battery Storage	Putnam County	Battery Storage
24	Sea Grape Battery Storage	St. Lucie County	Battery Storage
25	White Tail Battery Storage	Martin County	Battery Storage
26	Spanish Moss Solar Energy Center	St. Lucie County	Solar
27	County Line Solar Energy Center	Charlotte, DeSoto County	Solar
28	Hendry Solar Energy Center	Hendry County	Solar
29	Indrio Solar Energy Center	St. Lucie County	Solar
30	Middle Lake Solar Energy Center	Madison County	Solar
31	Saddle Solar Energy Center	DeSoto County	Solar
32	Tangelo Solar Energy Center	Okeechobee County	Solar
33	Wood Stork Solar Energy Center	St. Lucie County	Solar
34	Catfish Solar Energy Center	Okeechobee County	Solar
35	Cocoplum Solar Energy Center	Hendry County	Solar
36	Hardwood Hammock Solar Energy Center	Walton County	Solar
37	Joshua Creek Solar Energy Center	DeSoto County	Solar
38	Maple Trail Solar Energy Center	Baker County	Solar
39	Myakka Solar Energy Center	St. Lucie County	Solar
40	Pinecone Solar Energy Center	Calhoun County	Solar
41	Vernia Solar Energy Center	Indian River County	Solar
42	Blue Heron Battery Storage	Hendry County	Battery Storage
43	Green Pasture Battery Storage	Charlotte County	Battery Storage
44	Orange Blossom Battery Storage	Indian River County	Battery Storage
45	Sawgrass Battery Storage	Hendry County	Battery Storage

Table IV.G.1: List of FPL Preferred Sites Continued			
	Site Name	**County**	**Technology**
46	Swamp Cabbage Battery Storage	Hendry County	Battery Storage
47	Terrill Creek Battery Storage	Clay County	Battery Storage
48	Indrio Battery Storage	St. Lucie County	Battery Storage
49	Maple Trail Battery Storage	Baker County	Battery Storage
50	Monarch ACES Pilot Battery Storage	Martin County	Battery Storage
51	Monarch Battery Storage	Martin County	Battery Storage
52	Swallowtail Battery Storage	Walton County	Battery Storage
53	Union Springs Battery Storage	Union County	Battery Storage
54	Beachland Solar Energy Center	Indian River County	Solar
55	Bromeliad Solar Energy Center	Collier County	Solar
56	Honeybee Solar Energy Center	Collier County	Solar
57	Inlet Solar Energy Center	Indian River County	Solar
58	Sand Gully Solar Energy Center	DeSoto County	Solar
59	Shores Solar Energy Center	Indian River County	Solar
60	Ambersweet Solar Energy Center	Indian River County	Solar
61	Treefrog Solar Energy Center	Collier County	Solar
62	Wabasso Solar Energy Center	Indian River County	Solar
63	Waveland Solar Energy Center	St. Lucie County	Solar
64	Cardinal Solar Energy Center	Brevard County	Solar
65	Grapefruit Solar Energy Center	Hendry County	Solar
66	LaBelle Solar Energy Center	Hendry County	Solar
67	Mango Solar Energy Center	Hendry County	Solar
68	Owen Branch Solar Energy Center	Manatee County	Solar
69	Pine Lily Solar Energy Center	St. Lucie County	Solar
70	Redroot Solar Energy Center	Hendry County	Solar
71	Shell Creek Solar Energy Center	Charlotte, DeSoto County	Solar
72	Waxweed Solar Energy Center	Hendry County	Solar
73	Wild Lime Solar Energy Center	St. Lucie County	Solar
74	Grapefruit Battery Storage	Hendry County	Battery Storage
75	Mango Battery Storage	Hendry County	Battery Storage
76	Owen Branch Battery Storage	Manatee County	Battery Storage
77	Pine Lily Battery Storage	St. Lucie County	Battery Storage
78	Redroot Battery Storage	Hendry County	Battery Storage
79	Shell Creek Battery Storage	DeSoto, Charlotte County	Battery Storage
80	Waxweed Battery Storage	Hendry County	Battery Storage
81	Wild Lime Battery Storage	St. Lucie County	Battery Storage
82	Blanketflower Solar Energy Center	DeSoto County	Solar
83	Dove Solar Energy Center	DeSoto County	Solar
84	Ladybug Solar Energy Center	DeSoto County	Solar
85	Leafcutter Solar Energy Center	DeSoto County	Solar
86	Limpkin Solar Energy Center	Collier County	Solar
87	Spoonbill Solar Energy Center	Collier County	Solar
88	Caladium Solar Energy Center	Highlands County	Solar
89	New River Solar Energy Center	Union County	Solar
90	Blanketflower Battery Storage	DeSoto County	Battery Storage

Table IV.G.1: List of FPL Preferred Sites Continued			
	Site Name	**County**	**Technology**
91	Ladybug Battery Storage	DeSoto County	Battery Storage
92	Leafcutter Battery Storage	DeSoto County	Battery Storage
93	Turkey Point 6 & 7	Miami Dade County	Nuclear
94	Martin Power Plant	Martin County	Combustion Turbine

IV.G.2 Potential Sites

There are 38 Potential Sites currently identified for future generation and storage additions to meet projected capacity and energy needs. Each of these Potential Sites offers a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has distinctive characteristics that would require further definition and attention. Unless otherwise noted, the water quantities discussed below are in reference to universal solar generation rather than for gas-fueled generation.

Permits are considered obtainable for each site. No significant environmental constraints are currently known for any of these sites. FPL considers each site equally viable. These Potential Sites are listed in Table IV.G.2 below and are briefly discussed in the Appendix at the end of this document.

Table IV.G.2: List of FPL Potential Sites			
	Site Name	County	Technology
1	Harbortown Solar Energy Center	St. Lucie County	Solar
2	Horseback Solar Energy Center	St. Lucie County	Solar
3	Riverbreeze Solar Energy Center	St. Lucie County	Solar
4	Spruce Bluff Solar Energy Center	St. Lucie County	Solar
5	Cattail Solar Energy Center	Hendry County	Solar
6	Flamingo Solar Energy Center	Hendry County	Solar
7	Garberia Solar Energy Center	Manatee County	Solar
8	Periwinkle Solar Energy Center	Hendry County	Solar
9	Spider Lily Solar Energy Center	Manatee County	Solar
10	Sweetbroom Solar Energy Center	Hendry County	Solar
11	Carlton Solar Energy Center	St. Lucie County	Solar
12	Hummingbird Solar Energy Center	Martin County	Solar
13	Hurston Solar Energy Center	St. Lucie County	Solar
14	Jetty Park Solar Energy Center	St. Lucie County	Solar
15	Lagoon Solar Energy Center	St. Lucie County	Solar
16	Lancewood Solar Energy Center	Martin County	Solar
17	Lawnwood Solar Energy Center	St. Lucie County	Solar
18	Maypop Solar Energy Center	Martin County	Solar
19	Starboard Solar Energy Center	St. Lucie County	Solar
20	Wax Myrtle Solar Energy Center	Martin County	Solar
21	Edentown Solar Energy Center	Charlotte County	Solar
22	Mistflower Solar Energy Center	Charlotte County	Solar
23	Rosemary Solar Energy Center	Charlotte County	Solar
24	Sophia Solar Energy Center	Charlotte County	Solar
25	Spatterdock Solar Energy Center	Charlotte County	Solar
26	Tippen Solar Energy Center	Charlotte County	Solar
27	Woodpecker Solar Energy Center	Charlotte County	Solar
28	Yellowleg Solar Energy Center	Charlotte County	Solar
29	Cattail Battery Storage	Hendry County	Battery Storage
30	Flamingo Battery Storage	Hendry County	Battery Storage
31	Periwinkle Battery Storage	Hendry County	Battery Storage
32	Spiderlily Battery Storage	Manatee County	Battery Storage
33	Sweetbroom Battery Storage	Hendry County	Battery Storage
34	Northfork Power Plant	Clay County	Combustion Turbine
35	Okeechobee Power Plant	Okeechobee County	Combustion Turbine
36	Truman Power Plant	Putnam County	Combustion Turbine
37	Beaty Power Plant	Okeechobee County	Combustion Turbine
38	Hendry Power Plant	Hendry County	Combustion Turbine

(This page is intentionally left blank.)

CHAPTER V

Other Planning Assumptions & Information

(This page is left intentionally blank.)

Introduction

The FPSC, in Docket No. 960111-EU, specified certain information to be included in an electric utility's Ten-Year Power Plant Site Plan filing. This specified information includes 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations involve FPL's ties to its neighboring electric systems. Internal limitations involve the flow of electricity within the FPL system.

The external limitations are important because they affect the development of assumptions for the amount of external assistance that is available to the FPL area, as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance that is assumed to be available is based on the projected transfer capability to the FPL area from outside entities as well as historical levels of available assistance. In the LOLP portion of its reliability analyses, FPL's resource planning group has traditionally modeled the amount of external assistance as an additional generator(s) within the system that provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed in economic analyses by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within the system. The internal transmission limitations are also addressed by: 1) developing the direct costs for siting potential new units at different locations, 2) evaluating the cost impacts created by the new unit/unit location combination on the operation of existing generating units in the system, and/or 3) evaluating the costs of transmission and/or generation additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Costs for these site, region, and system factors are developed for use in economic analyses. These factors are also considered in both system and regional reliability analyses. When analyzing DSM portfolios, such as for a DSM Goals docket, the potential to avoid or defer regional transmission additions that might otherwise be needed is typically

analyzed. In addition, transfer limits for capacity and energy that can be transferred between FPL and FPL NWFL service areas are also developed, as applicable, for use in reliability analyses and production costing analyses.

Annual transmission planning work determines transmission additions needed to address limitations and maintain/enhance system and regional reliability. Planned transmission facilities to interconnect and integrate generating units in the resource plan, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL's resource planning group typically performs economic analyses of competing resource plans using levelized system average electric rates (*i.e.*, a Rate Impact Measure or RIM approach) as an economic criterion. In addition, for analyses in which DSM levels are not changed and only supply options are analyzed, the equivalent criterion of the cumulative present value of revenue requirements (CPVRR) may also be used.[5] This type of evaluation was used in developing the resource plan for the 2026 Site Plan.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenarios. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions used to derive fuel price forecasts are discussed in Chapter III of this document. FPL's resource planning group may use a single fuel cost forecast, or multiple fuel cost forecasts (Low, Medium, and High), in its analyses as appropriate.

[5] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (*i.e.*, when only new generating options are considered), the lowest electric rate basis approach and the lowest system CPVRR basis approach yield identical results in terms of which resource options are more economic. In such cases, resource options can be evaluated on the simpler-to-calculate (but equivalent) lowest CPVRR basis.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. Then the approach has been to adjust the Medium fuel cost forecast upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based on an updated fuel cost forecast developed in September 2025.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

In its 2025 and early 2026 resource planning work, a forecast scenario in which the differential between oil/gas and coal was held constant was not utilized. This is, in part, because FPL is currently using small amounts of oil as a fuel and is projecting to use very little coal as a fuel during the ten-year period. These trends are shown on Schedules 5, 6.1, and 6.2 in Chapter III.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units is modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of the existing generating units. The values used for outages and heat rates are generally consistent with the values that have been used in planning studies in recent years.

For new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating and maintenance costs, capital replacement costs, construction schedules, heat rates (as appropriate), and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options that FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The financial assumptions used in the resource planning analyses that led to the resource plan that is presented in this 2026 Site Plan were: in late 2025, an incremental capital structure of 40.40% debt and 59.60% equity; (ii) a 5.68% cost of debt; (iii) a 10.95% return on equity; and (iv) an after-tax discount rate of 8.24%. In early 2026, these assumptions were changed to: an incremental capital structure of 40.40% debt and 59.60% equity; (ii) a 5.83% cost of debt; (iii) a 10.95% return on equity; and (iv) an after-tax discount rate of 8.28%. No other financial assumptions were used in the 2025 and early 2026 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's IRP process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on electricity rate levels, with the objective generally being to minimize the projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the CPVRR perspective for the system yield identical results in terms of which resource options are more economical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, FPL's resource planning group utilizes the equivalent, but simpler-to-calculate CPVRR perspective.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL's resource planning group uses three system reliability criteria in its resource planning work that address various resource options including: utility generation, power purchases, and DSM options. One criterion is a minimum 20% Summer and Winter total reserve margin. Another reliability criterion is a maximum of 0.1 days per-year LOLP. The third criterion is a minimum 10% GRM. These three reliability criteria are discussed in Chapter III of this document.

For transmission reliability analysis, transmission planning criteria have been adopted that are consistent with those established by the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Corporation (SERC). The FRCC and SERC have adopted transmission planning criteria that are consistent with the Reliability Standards established by the NERC. The *NERC Reliability Standards* are available on the NERC internet site (http://www.nerc.com/).

In addition, *Facility Interconnection Requirements* (FIR) documents for the FPL system have been developed. The document for FPL is available on FPL's Open Access Same-time Information System (OASIS) website, https://www.oatioasis.com/FPL/index.html, under the "Interconnection Request Information" directory. Furthermore, all new transmission facilities within the FPL service territory that are used to meet FPL load are planned to comply with Extreme Wind Loading Criteria as implemented in FPL Design Guidelines.

FPL's transmission planning group generally limits planned flows on its transmission facilities to no more than 100% of the applicable thermal rating. There may be isolated cases for which it is acceptable to deviate from the general criteria stated below. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, transmission system performance, and other factors.

The normal and contingency voltage criteria for FPL stations are provided below:

Normal/Contingency[6]

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
161	0.95/0.95	1.05/1.10
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.10
Turkey Point (*)	1.013/1.013	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

[6] Immediately following a contingency, steady-state voltages may deviate from the normal voltage range if there are known automatic or manual operating actions to adjust the voltage to within the contingency voltage range. However, the steady-state voltage must never exceed voltage System Operating Limits (SOLs), which have a lower limit of 0.90pu and a higher limit of 1.10pu for all transmission facilities, excluding nuclear plant switchyards for which the SOLS are equal to the normal/contingency limits.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

FPL periodically revises the projected impacts of its DSM programs on demand and energy consumption. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of its load management equipment to ensure it is functioning correctly. These tests, plus actual load management events, also allow FPL to gauge the MW reduction capabilities of its load management programs on an ongoing basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors that FPL's resource planning group typically considers when choosing among resource options. These include: (1) technology risk; (2) environmental risk; and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects. Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology that has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, assuming all else is equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the utility system, including projected environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a prospective resource plan are those that minimize environmental impacts for the utility system as a whole through highly efficient fuel use, state-of-the-art environmental controls, and generating technologies that do not utilize fossil fuels (such as nuclear and solar).

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with fewer barriers to successful development.

All of these factors play a part in resource planning and decision-making, including decisions to construct capacity or purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2026 Site Plan, the current resource plan reflects the following major supply-side or generation resource additions in FPL's area: CT component upgrades at various existing CCs, addition of new PV facilities, the addition of new battery storage facilities, and potential new CT additions.

CT upgrades are planned to take place at various CC units throughout the FPL area that address Summer and Winter capacity. The original equipment manufacturers (OEM) of the CTs approached FPL regarding the possibility of upgrading these units. Following negotiations with the OEMs and economic analyses that showed upgrading was cost-effective for customers, FPL decided to proceed with the CT upgrades and the supporting balance of plant modifications.

For new solar, battery and gas generation facilities for FPL, the selection of equipment and installation contractors has been, and will continue to be, done via competitive bidding. FPL's Engineering & Construction (E&C) group seek bids from multiple suppliers for major components such as PV panels, inverters, batteries, combustion turbine generators (CT) and step-up transformers. Where possible, volume is leveraged to achieve economies of scale and options are evaluated based on total cost of ownership. Remaining balance-of-system (BOS) material purchases, as well as engineering and construction services, are typically competitively bid out as well to determine the best value.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL has identified the need for two new transmission line projects that require certification under the Transmission Line Siting Act (as shown on Table III.E.1 in Chapter III).

Sweatt-Whidden

The 230 kV line will connect FPL's Whidden Substation to a new Sweatt 230 kV Substation. A determination of need for the line was filed with the FPSC in April 2022, and a final order certifying the

corridor for the project was issued in September 2022. The project is scheduled to be completed by June 2026. The construction of this line and substation is necessary to serve existing and future FPL customers in the west Florida area in and around Okeechobee, Highlands, Desoto, Collier, Lee, Sarasota, and Manatee Counties in a reliable and effective manner.

Andytown-Oasis

The Andytown-Oasis transmission lines project involves the construction of four new transmission lines: (1) one 500 kV line starting at FPL's existing Andytown substation in Broward County and ending at FPL's planned Oasis substation in Miami-Dade County; (2) one 500 kV line starting at FPL's existing Quarry substation in Miami-Dade County and ending at FPL's planned Oasis substation in Miami-Dade County; (3) one 230 kV line starting at FPL's planned Oasis substation in Miami-Dade County and ending at FPL's existing Quarry substation in Miami-Dade County; and (4) one 230 kV line starting at FPL's planned Oasis substation in Miami-Dade County and ending at FPL's existing Levee substation in Miami-Dade County. A determination of need for FPL's proposed Andytown-Oasis transmission lines project was filed with the FPSC in March 2026. The project has a planned in-service date of December 2033. The Project consists of four related transmission lines that are each necessary and appropriate to (a) address future thermal overloads and low voltage conditions in Miami-Dade County under contingency events in compliance with NERC Reliability Standards TPL-001-5.1 and NUC-001-4; (b) maintain transmission reliability for FPL customers in Miami-Dade County; and (c) increase power transfer capability of the transmission system to support Miami-Dade County's growing demand.

(This page is left intentionally blank.)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 12

REVIEW OF THE 2025 TEN YEAR SITE PLANS OF FLORIDA'S ELECTRIC UTILITIES

REVIEW OF THE

2025 TEN YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC
SERVICE COMMISSION

NOVEMBER 2025

Table of Contents

List of Figures ..... **iii**
List of Tables ..... **v**
List of TYSP Utilities vii
Unit Type, Fuel, and Other Abbreviations vii
Executive Summary **1**
Review of the 2025 TYSPs 2
Future Considerations 5
Conclusion 6
Introduction **7**
Statutory Authority 7
Structure of the Commission's Review 9
Conclusion 9
Statewide Perspective **11**
Load Forecasting **13**
Electric Customer Composition 13
Growth Projections 13
Peak Demand 15
Electric Vehicles 17
Data Centers 19
Demand-side Management (DSM) 20
Forecast Load and Peak Demand 22
Forecast Methodology 24
Accuracy of Retail Energy Sales Forecast 25
Renewables and Energy Storage **29**
Existing Renewable Resources 29
Utility-Owned Renewable Generation 30
Non-Utility Renewable Generation 30
Customer-Owned Renewable Generation 31
Planned Renewable Resources 31
Energy Storage 33
Traditional Generation **35**
Existing Generation 35
Modernization and Efficiency Improvements 36
Planned Retirements 37
Reliability Requirements 38
Fuel Price Forecast 42

Fuel Diversity 43
New Generation Planned 45
Commission's Authority Over Siting 46
New Power Plants by Fuel Type 46
Transmission 47
Utility Perspectives 49
Florida Power & Light Company (FPL) 51
Duke Energy Florida, LLC (DEF) 59
Tampa Electric Company (TECO) 65
Florida Municipal Power Agency (FMPA) 71
Gainesville Regional Utilities (GRU) 77
JEA 83
Lakeland Electric (LAK) 89
Orlando Utilities Commission (OUC) 95
Seminole Electric Cooperative (SEC) 101
City of Tallahassee Utilities (TAL) 107

List of Figures

Figure 1: State of Florida - Growth in Customers and Sales 2
Figure 2: State of Florida - Electricity Generation Sources 4
Figure 3: State of Florida - Current and Projected Installed Capacity 5
Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Sales 8
Figure 5: State of Florida - Electric Customer Composition in 2024 13
Figure 6: State of Florida - Growth in Customers and Sales 14
Figure 7: National - 20 Year Average Climate Data by State (Continental U.S.) 16
Figure 8: TYSP Utilities - Example Daily Load Curves 16
Figure 9: TYSP Utilities - Daily Peak Demand (2024 Actual) 17
Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy 23
Figure 11: State of Florida – Current and Projected Renewables and Energy Storage 31
Figure 12: TYSP Utilities - Planned Solar Installations 32
Figure 13: FPL 2024 Summer Peak Day Hourly Dispatch 33
Figure 14: State of Florida - Electric Utility Installed Capacity by Decade 35
Figure 15: State of Florida - Projected Reserve Margin by Season 40
Figure 16: State of Florida - Projected Summer Reserve Margin without Solar 41
Figure 17: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities 43
Figure 18: State of Florida - Natural Gas Generation 43
Figure 19: State of Florida - Historic and Forecast Generation by Fuel Type 44
Figure 20: State of Florida - Current and Projected Installed Capacity 45
Figure 21: FPL Growth 52
Figure 22: FPL Demand and Energy Forecasts 53
Figure 23: FPL Reserve Margin Forecast 55
Figure 24: DEF Growth 60
Figure 25: DEF Demand and Energy Forecasts 61
Figure 26: DEF Reserve Margin Forecast 63
Figure 27: TECO Growth 66
Figure 28: TECO Demand and Energy Forecasts 67
Figure 29: TECO Reserve Margin Forecast 69
Figure 30: FMPA Growth 72
Figure 31: FMPA Demand and Energy Forecasts 73
Figure 32: FMPA Reserve Margin Forecast 75
Figure 33: GRU Growth 78
Figure 34: GRU Demand and Energy Forecasts 79
Figure 35: GRU Reserve Margin Forecast 81
Figure 36: JEA Growth 84
Figure 37: JEA Demand and Energy Forecasts 85
Figure 38: JEA Reserve Margin Forecast 87
Figure 39: LAK Growth 90
Figure 40: LAK Demand and Energy Forecasts 91
Figure 41: LAK Reserve Margin Forecast 93
Figure 42: OUC Growth 96
Figure 43: OUC Demand and Energy Forecasts 97
Figure 44: OUC Reserve Margin Forecast 99
Figure 45: SEC Growth 102

Figure 46: SEC Demand and Energy Forecasts 103
Figure 47: SEC Reserve Margin Forecast 105
Figure 48: TAL Growth 108
Figure 49: TAL Demand and Energy Forecasts 109
Figure 50: TAL Reserve Margin Forecast 111

List of Tables

Table 1: State of Florida - Renewable Energy Generation 3
Table 2: TYSP Utilities - Electric Vehicle Projections 18
Table 3: TYSP Utilities - Data Centers by Utility 19
Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts 25
Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis 26
Table 6: State of Florida - Existing Renewable Resources 29
Table 7: State of Florida - Customer-Owned Renewable Growth 31
Table 8: State of Florida - Electric Generating Units to be Retired 38
Table 9: FRCC Loss of Load Probability Study Results 42
Table 10: TYSP Utilities - Planned Natural Gas Units 47
Table 11: State of Florida - Planned Transmission Lines 48
Table 12: FPL Energy Generation by Fuel Type 54
Table 13: FPL Generation Resource Changes 57
Table 14: DEF Energy Generation by Fuel Type 62
Table 15: DEF Generation Resource Changes 64
Table 16: TECO Energy Generation by Fuel Type 68
Table 17: TECO Generation Resource Changes 70
Table 18: FMPA Energy Generation by Fuel Type 74
Table 19: FMPA Generation Resource Changes 76
Table 20: GRU Energy Generation by Fuel Type 80
Table 21: GRU Generation Resource Changes 82
Table 22: JEA Energy Generation by Fuel Type 86
Table 23: JEA Energy Generation by Fuel Type 88
Table 24: LAK Energy Generation by Fuel Type 92
Table 25: LAK Generation Resource Changes 94
Table 26: OUC Energy Generation by Fuel Type 98
Table 27: OUC Generation Resource Changes 100
Table 28: SEC Energy Generation by Fuel Type 104
Table 29: SEC Generation Resource Changes 106
Table 30: TAL Energy Generation by Fuel Type 110

List of TYSP Utilities

Name	Abbreviation
Investor-Owned Electric Utilities	
Florida Power & Light Company	FPL
Duke Energy Florida, LLC	DEF
Tampa Electric Company	TECO
Municipal Electric Utilities	
Florida Municipal Power Agency	FMPA
Gainesville Regional Utilities	GRU
JEA	JEA
Lakeland Electric	LAK
Orlando Utilities Commission	OUC
City of Tallahassee Utilities	TAL
Rural Electric Cooperatives	
Seminole Electric Cooperative	SEC

Unit Type, Fuel, and Other Abbreviations

Reference	Name	Abbreviation
Unit Type	Battery Storage	BAT
	Combined Cycle	CC
	Combustion Turbine	CT
	Hydroelectric	HY
	Internal Combustion	IC
	Photovoltaic	PV
	Steam Turbine	ST
Fuel Type	Bituminous Coal	BIT
	Distillate Fuel Oil	DFO
	Landfill Gas	LFG
	Natural Gas	NG
	Nuclear	NUC
Other	Ten Year Site Plan	TYSP

Executive Summary

Integrated resource planning (IRP) is a utility process that includes a cost-effective combination of demand-side resources and supply-side resources. While each utility has slightly different approaches to IRP, some things are consistent across the industry. Each utility must update its load forecast assumptions based on Florida Public Service Commission (Commission) decisions in various dockets, such as demand-side management goals. Changes in government mandates, such as appliance efficiency standards, building codes, and environmental requirements must also be considered. Other updates involve input assumptions like demographics, financial parameters, generating unit operating characteristics, and fuel costs which are more fluid and do not require prior approval by the Commission. Each utility then conducts a reliability analysis to determine when resources may be needed to meet expected load. Next, an initial screening of demand-side and supply-side resources is performed to find candidates that meet the expected resource need. The demand-side and supply-side resources are combined in various scenarios to decide which combination meets the need most cost-effectively. After the completion of all these components, utility management reviews the results of the varying analyses and the utility's TYSP is produced as the culmination of the IRP process. Commission Rules also require the utilities to provide aggregate data which provides an overview of the State of Florida electric grid.

The Commission's annual review of utility TYSPs is non-binding in accordance with Section 186.801(2), Florida Statutes (F.S.), but it does provide state, regional, and local agencies advance notice of proposed power plants and transmission facilities. Any concerns identified during the review of the utilities' TYSPs may be addressed by the Commission at a formal public hearing, such as a power plant need determination proceeding. While Florida Statutes and Commission Rules do not specifically define IRP, they do provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Pursuant to Section 186.801, F.S., each generating electric utility must submit to the Commission a TYSP which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The TYSPs of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2025 TYSPs for Florida's electric utilities, as filed by 10 reporting utilities.[1]

All findings of the Commission are made available to the Florida Department of Environmental Protection for its consideration at any subsequent certification proceeding pursuant to the Florida

[1] Investor-owned utilities filing 2025 TYSPs include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2025 TYSPs include Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. Seminole Electric Cooperative also filed a 2025 TYSP.

Electrical Power Plant Siting Act or the Florida Electric Transmission Line Siting Act.[2] In addition, this document is sent to the Florida Department of Agriculture and Consumer Services pursuant to Section 377.703(2)(e), F.S., which requires the Commission provide a report on electricity and natural gas forecasts.

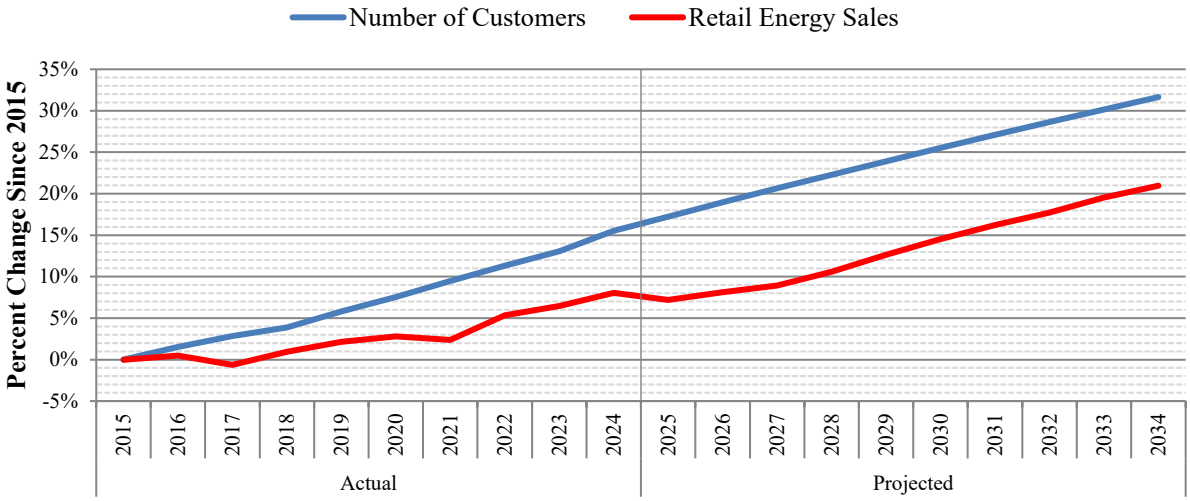
Review of the 2025 TYSPs

The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's electric utilities regarding load forecasting, renewable generation, and traditional generation.

Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested forecasting methodologies, which are consistent with industrywide practices used in generation planning. Figure 1 provides the historical and forecasted trends in customer growth and energy sales. Normalized weather trends were used to forecast 2025 through 2034, which start slightly below the actual 2024 level but increase annually at 1.35 percent.

Figure 1: State of Florida - Growth in Customers and Sales



Source: Florida Reliability Coordinating Council (FRCC) 2025 Regional Load and Resource Plan

[2] The Florida Electrical Power Plant Siting Act is Sections 403.501 through 403.518, F.S. Pursuant to Section 403.519, F.S., and the Commission is the exclusive forum for the determination of need for an electrical power plant. The Florida Electric Transmission Line Siting Act is Sections 403.52 through 403.5365, F.S. Pursuant to Section 403.537, F.S., and the Commission is the sole forum for the determination of need for a transmission line.

Renewable Generation

Renewable resources continue to expand in Florida, with approximately 14,723 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar photovoltaic (PV) generation which makes up approximately 90 percent of Florida's existing renewables. Notably, Florida electric customers had installed 2,801 MW of demand-side renewable capacity by the end of 2024, an increase of 19 percent from 2023.

Florida's total renewable resources are expected to increase by approximately 26,228 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase. Table 1 provides a breakdown of each TYSP Utility's actual 2024 and projected 2034 generation from renewables, in gigawatt-hours (GWh) and as a percentage of the net energy for load (NEL). Renewable energy as a percentage of NEL is expected to increase from 7.8 percent in 2024 to 29.2 percent in 2034. On a statewide level, solar generation will account for 27.7 percent of NEL in 2034.

Table 1: State of Florida - Renewable Energy Generation

Utility	2024 Actual			2034 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL	146,102	13,449	9.2%	160,473	56,831	35.4%
DEF	44,200	3,354	7.6%	46,359	13,250	28.6%
TECO	21,852	2,235	10.2%	23,374	5,870	25.1%
FMPA	7,172	161	2.2%	7,006	340	4.9%
GRU	1,903	253	13.3%	1,997	654	32.8%
JEA	13,254	507	3.8%	14,043	2,832	20.2%
LAK	3,509	28	0.8%	3,794	194	5.1%
OUC	8,206	408	5.0%	9,532	4,791	50.3%
TAL	2,849	96	3.4%	2,922	111	3.8%
SEC	17,359	383	2.2%	23,368	703	3.0%
STATE	266,406	20,874	7.8%	292,868	85,576	29.2%

Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

While solar makes notable contributions to NEL, it is not considered a firm resource and contributes only a portion of its capacity during the period of system peaks. Generally, solar makes a contribution toward summer peaks and no, or minimal, contribution to winter peaks. As the amount of solar generation in a utility system grows, this value is reduced as the net solar system peak is shifted further into the evening, when solar generation declines, increasing the need for non-solar generation to start or ramp up production. As a result, existing solar is considered firm towards summer peaks for approximately 35.4 percent of its capacity, while planned solar is considered firm for only 11.4 percent of its capacity.

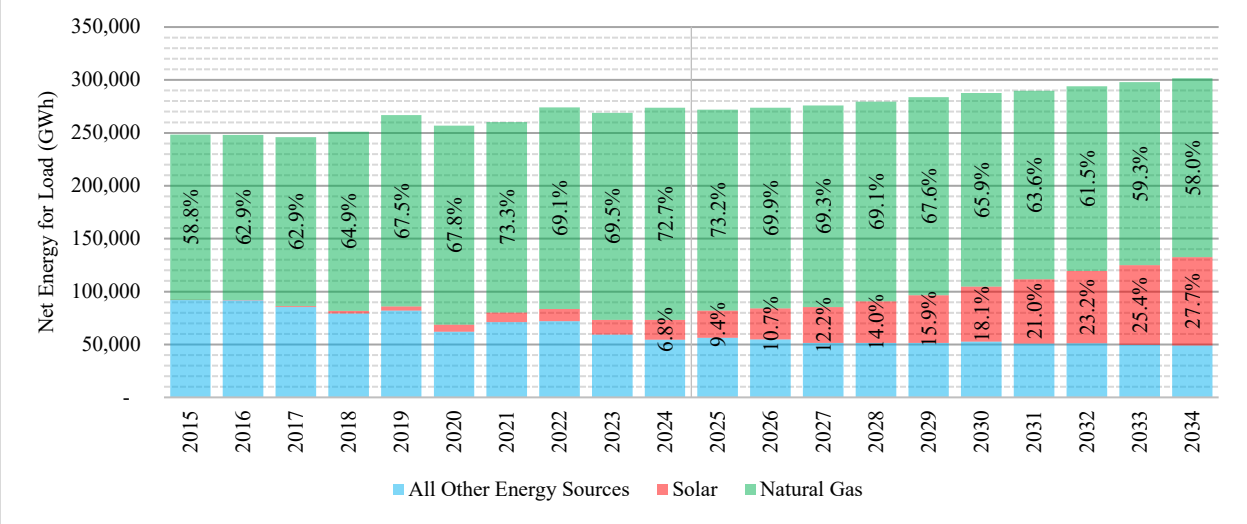
Battery Storage

Addressing this concern is a relatively new technological entry in Florida's generation mix, energy storage, primarily in the form of batteries. While the first 1.5 MW pilot battery storage facility entered service in 2016, a total of 604 MW of battery storage was installed by 2024, and an additional 10,031 MW will enter service by 2034. Battery storage is a unique resource in that it can contribute to firm capacity and offers a fast ramp rate; however, it has a limited duration and requires charging from the grid, becoming load rather than generation. Battery storage can be charged by any generation resource. Given these characteristics, for reliability planning purposes, only 548 MW of existing battery storage and 5,673 MW of planned battery storage is considered firm for summer peaks. The Commission will continue to monitor technological developments in renewable generation and energy storage to cost-effectively address the state's fuel diversity, reducing the dependence on fossil fuels, while still maintaining adequate resources to provide for customer loads.

Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,715 MW of traditional generation over the planning horizon and with natural gas plant additions offset by coal and oil retirements. Natural gas electric generation, as a percent of NEL, is expected to decline from 72.7 percent in 2024 to 58.0 percent over the planning horizon. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida compared to solar and all other energy sources combined. The total energy produced by solar generation is projected to exceed all other sources combined, excluding natural gas, by 2031.

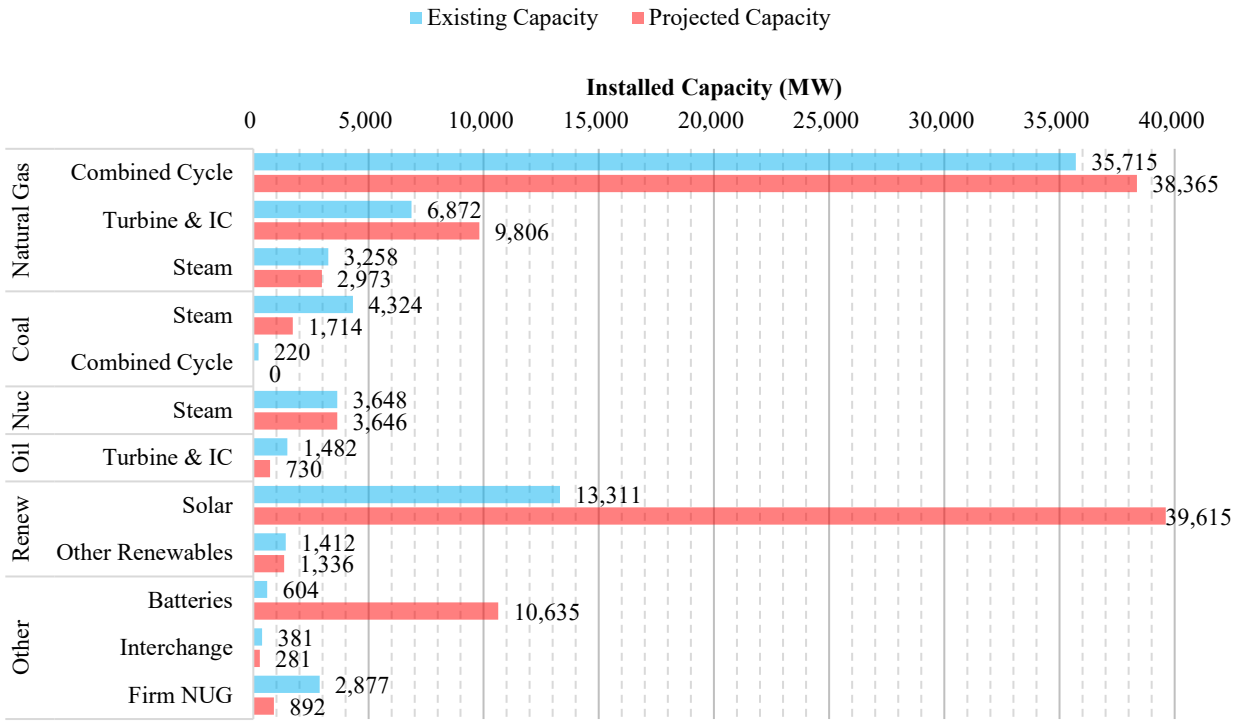
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2016-2025 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2025 TYSPs. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. While natural gas-fired generating units represent a majority of capacity within the state, renewable capacity additions make up the majority of the projected net increase in generation capacity over the planning period. Solar generation is already the second highest category of installed capacity and will exceed natural gas combined cycle nameplate capacity by the end of the 10-year planning period. As mentioned previously, not all of the installed solar capacity provides a firm resource that is available to serve peak demand.

Figure 3: State of Florida - Current and Projected Installed Capacity



Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

The primary purpose of this review is to provide information regarding proposed electric power plants for local, regional, and state agencies to assist in the certification process. During the next 10 years, there are two new units planned by JEA and SEC that may require a determination of need from the Commission pursuant to Section 403.519, F.S., both natural gas-fired combined cycles, in 2030 and 2032, respectively. The Commission can anticipate filings for need determinations sometime in 2026 and 2028 for these units, assuming a petition is filed four years before the in-service date.

Future Considerations

Florida's electric utilities must consider changes in environmental regulations associated with existing generators and planned generation to meet Florida's electric needs. Developments in the U.S. Environmental Protection Agency (EPA) regulations may impact Florida's existing

generation fleet and proposed new facilities. For example, on June 17, 2025, the EPA published a proposed rule to repeal all Greenhouse Gas (GHG) standards for fossil fuel-fired power plants, arguing that GHG emissions from these plants do not significantly contribute to dangerous air pollution. On March 12, 2025, the EPA also announced that it will undertake 31 actions to advance President Trump's Executive Orders. These actions include the reconsideration of regulations on power plants and introducing the Clean Power Plan 2.0, and the reconsideration of limitations, guidelines, and standards for steam powered electric generating units. These and other relevant EPA actions are further discussed in the Traditional Generation section below.

Emerging Trends

Florida's electric industry is experiencing heightened demand for power from customers influenced by the potential expansion of data centers. Florida utilties recognize the associated substantial increase in load to serve such customers and, to the extent such load materialize, they will require significant new infrastruture in both generation and transmission. As such, the utilities are actively assessing the potential impact of load growth driven by the advent of large data centers, including protections to their existing customers from the risks associated with potential stranded costs incurred to install new or upgraded facilities to serve a new large data center. Increased loads can be met on the utility side by improving existing generation and transmission infrastructure to allow more energy-efficient production and delivery of electricity or with the addition of new resources such as battery energy storage. Other developments, such as potential new nuclear generation in the form of small modular reactors, may have the potential to change Florida's energy landscape in the future. As these new technologies evolve, the Commission will continue its oversight as these impacts are included in future electric utility TYSPs.

Conclusion

The Commission has reviewed the 2025 TYSPs of Florida's electric utilities and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity. The Commission will continue to monitor the impact of current and proposed EPA Rules, expansion of electric vehicle (EV) adoption, and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2025 TYSPs to be suitable for planning purposes. Since the plans are not a binding plan of action for electric utilities, the Commission's classification of these plans as "suitable" or "unsuitable" does not constitute a finding or determination in docketed matters before the Commission.

Introduction

The TYSPs of Florida's electric utilities are the culmination of an integrated resource plan which is designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. The TYSPs are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

For any new proposed power plants and transmission facilities, certification proceedings under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, F.S., or the Florida Electric Transmission Line Siting Act, Sections 403.52 through 403.5365, F.S., will include more detailed information than is provided in the TYSPs. The Commission is the exclusive forum for determination of need for electrical power plants, pursuant to Section 403.519, F.S., and for transmission lines, pursuant to Section 403.537, F.S. The TYSPs are not intended to be comprehensive, and therefore may not have sufficient information to allow regional planning councils, water management districts, and other reviewing state, regional, and local agencies to evaluate site-specific issues within their respective jurisdictions. Other regulatory processes may require the electric utilities to provide additional information as needed.

Statutory Authority

Section 186.801, F.S., requires that all major generating electric utilities submit a TYSP to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each TYSP and makes a non-binding determination as to whether the plan is suitable or unsuitable. The results of the Commission's study are contained in this report and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, and forward this information to the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.), in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Applicable Utilities

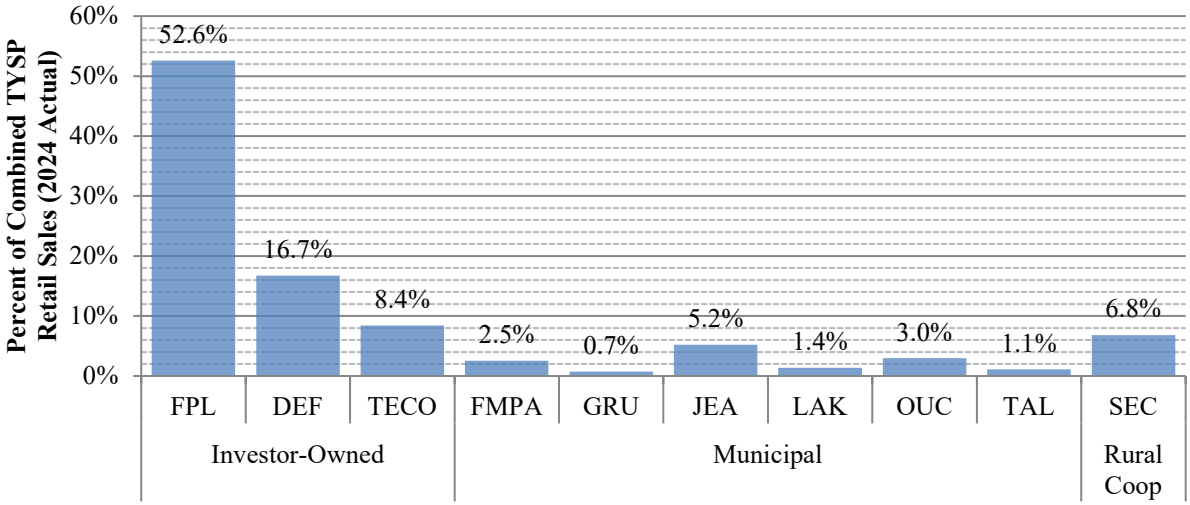
Florida is served by 57 electric utilities, including 4 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only electric utilities with an existing generating capacity above 250 MW or a planned unit with a capacity of 75 MW or greater are required to file a TYSP with the Commission every year.

In 2025, 10 utilities met these requirements and filed a TYSP, including 3 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), and Tampa Electric Company (TECO). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of

Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2025 TYSP is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the TYSP Utilities.

Figure 4 illustrates the comparative size of the TYSP Utilities in terms of each utility's percentage share of the combined TYSP Utilities' retail energy sales in 2024. Collectively, the reporting investor-owned utilities account for 77.7 percent of statewide retail energy sales, while the municipal and cooperative utilities make up approximately 20.8 percent of the statewide retail energy sales. The remainder is associated with non-reporting entities due to their limited size.

Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Sales



Source: FRCC 2025 Regional Load and Resource Plan and 2025 TYSPs

Required Content

The Commission requires each reporting utility to provide information on a variety of topics as required by Section 186.801(2) F.S. Schedules describe the utility's existing generation fleet, customer composition, demand and energy forecasts, fuel requirements, reserve margins, changes to existing capacity, and proposed power plants and transmission lines. The utilities also provide a narrative documenting the methodologies used to forecast customer demand and the identification of resources to meet that demand over the 10-year planning period. This information, supplemented by additional data requests, provides the basis of the Commission's review.

Additional Resources

The Florida Reliability Coordinating Council (FRCC) compiles utility data on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. This provides aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. For certain comparisons, the Commission employs additional data from various government agencies, including the U. S. Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

Structure of the Commission's Review

The Commission's review is divided into multiple sections. The Statewide Perspective provides an overview of Florida as a whole, including discussions of load forecasting, renewable generation, and traditional generation. The Utility Perspectives provides more focus, discussing the various issues facing each electric utility and its unique situation. Comments collected from various review agencies, local governments, and other organizations are included in Appendix A.

Conclusion

Based on its review, the Commission finds all 10 reporting utilities' 2025 TYSPs to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity.

The Commission notes that the TYSPs are non-binding, and a classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the TYSPs.

Statewide Perspective

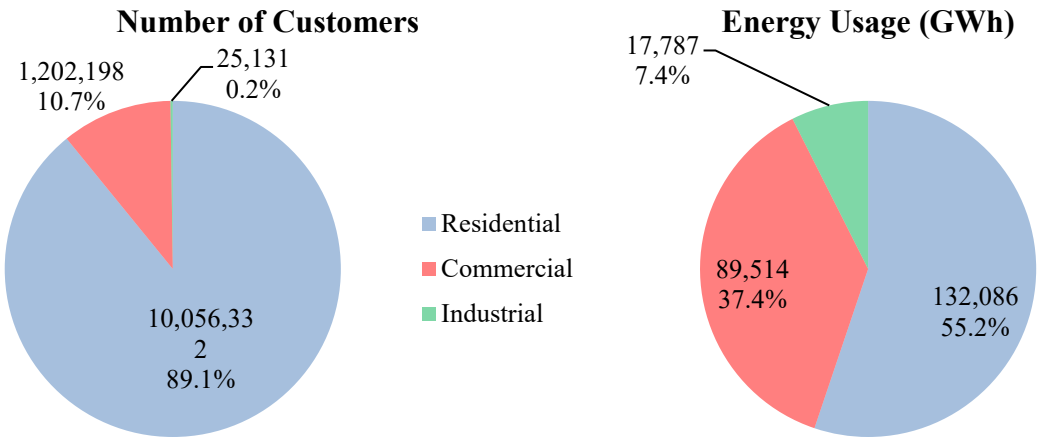
Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested methodologies for preparing customer, energy, and peak demand forecasts.

Electric Customer Composition

Utility companies categorize their customers by residential, commercial, and industrial classes. As illustrated in Figure 5, residential customers account for 89.1 percent of the total, followed by commercial (10.7 percent) and industrial (0.2 percent) customers. Commercial and industrial customers make up a sizeable percentage of energy sales due to their higher energy usage per customer. Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55.2 percent of retail energy sales in 2024, compared to a national average of approximately 37.4 percent in 2023.[3]

Figure 5: State of Florida - Electric Customer Composition in 2024



Source: FRCC 2025 Regional Load and Resource Plan

Growth Projections

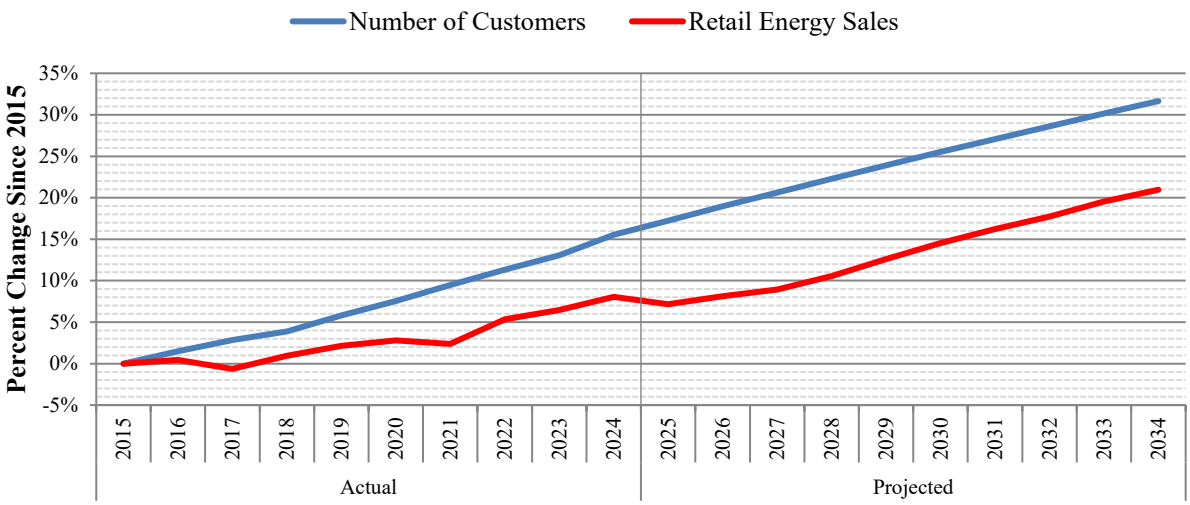
For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.35 percent per year, compared to the 0.86 percent actual annual increase experienced during the 2015-2024 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.30 percent for the next 10-year period, compared to the 1.62

[3] U.S. Energy Information Administration – Electric Power Annual, released October 17, 2024.

percent actual annual increase experienced during the last decade. These trends are showcased in Figure 6.

As shown in Figure 6, Florida utilities' total retail energy sales reached a historical peak in 2024, surpassing the most recent peak that was reached in 2022. Several factors converged to contribute to this effect: continued growth in the number of retail customers as more people relocated to the state; warmer-than-normal weather conditions; and a surge in economic activity within the state's tourism and service sectors as they continued to recover from the COVID-19 pandemic, leading to increased electricity consumption across various industries. Florida utilities' total retail energy sales are projected to continuously grow at a moderate annual average rate for the next 10 years. This sales growth is driven by an anticipated growth in customers and business activity (such as the addition of large load customers like data centers) as well as the expected increased level of adoption of EV vehicles.

Figure 6: State of Florida - Growth in Customers and Sales



Source: FRCC 2025 Regional Load and Resource Plan

The projected retail energy sales trend reflects the product of the utilities' forecasted number of customers and forecasted energy usage per customer (UPC). The key factor affecting utilities' number of customers is population growth. The key factors affecting utilities' average UPC includes weather variability, economic conditions, and changes in customer behavior or operations; hence, the corresponding information is utilized to develop the forecast models for projecting future growth of UPC. The projected growth rate of retail energy sales is impacted by these underlying key factors.

With respect to the UPC projection over the current forecast period, FPL's residential class UPC is expected to decline gradually over time, primarily driven by continued improvements in energy efficiency and increasing customer adoption of energy-saving behaviors and technologies. FPL's commercial class UPC is expected to be generally flat to slightly declining for similar reasons, and

its industrial UPC is predicted to increase modestly overall, driven by the additional usage by expected new large load customers.

Meanwhile, DEF reported that its residential and commercial UPC, respectively, decreased at a compounded annual growth rate of 0.7 percent and 0.8 percent. This decrease is primarily driven by fluctuations in price of electricity, end-use appliance saturation and efficiency improvements, more stringent building codes, housing type/size, and the energy source of air conditioning equipment. In addition, DEF is aware that more recently, the customer's ability to self-generate has begun to make an impact on the UPC numbers. For example, DEF noted a small percentage of industrial/commercial customers have chosen to install their own natural gas generators, reducing energy consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind the meter. DEF also noted that, while the penetration of plug-in EVs has grown, working to increase residential UPC, rooftop solar generation continues to outweigh consumption from EV.

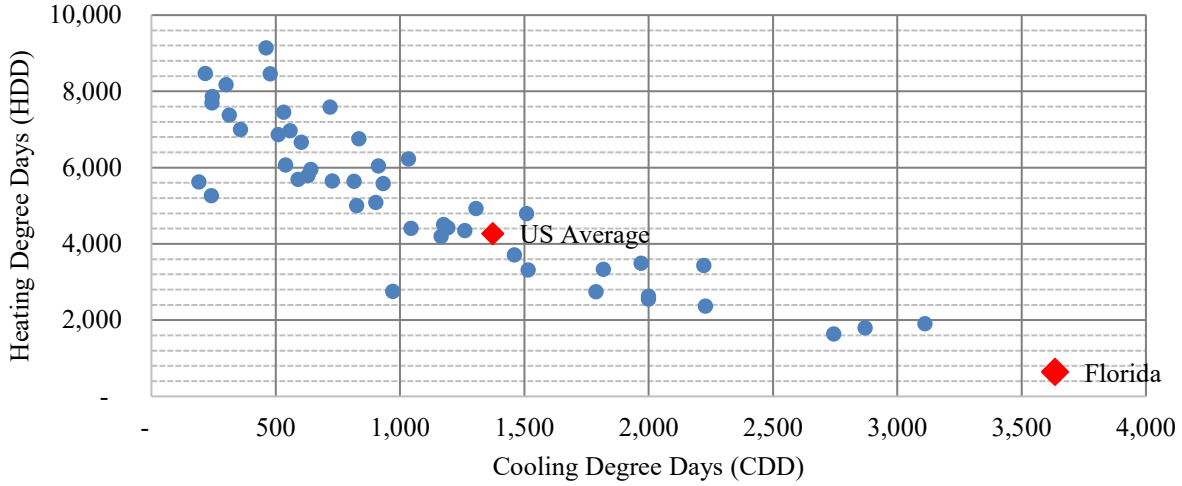
In west central Florida, TECO's residential class UPC is expected to decline at an average annual rate of 0.3 percent, primarily due to increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and housing mix. TECO's commercial and industrial UPC are projected to decrease slightly at a rate of 0.1 percent and 0.2 percent a year, respectively. Likewise, other TYSP Utilities reported that the downward trend in UPC is due to advancements in technologies for energy efficiency, renewable generation, and alternative energy sources, with some TYSP Utilities expecting that increased residential at-home EV charging and the impact of anticipated energy-intensive commercial/industrial customers will mitigate this downward pressure to some extent.

Peak Demand

The aggregation of each individual customer's electric consumption must be met at all times by Florida's electric utilities to ensure reliable service. The time at which customers demand the most energy simultaneously is referred to as peak demand. While retail energy sales dictate the amount of fuel consumed by the electric utilities to deliver energy, peak demand determines the amount of generating capacity required to deliver that energy at a single moment in time. As a result of the high contribution of residential customers to NEL, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions.

Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown in Figure 7. As such, most of Florida's utilities experience their peak demand during summer months. However, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs. Even with the low frequency of heating days required, such reliance can impact winter peak demand.

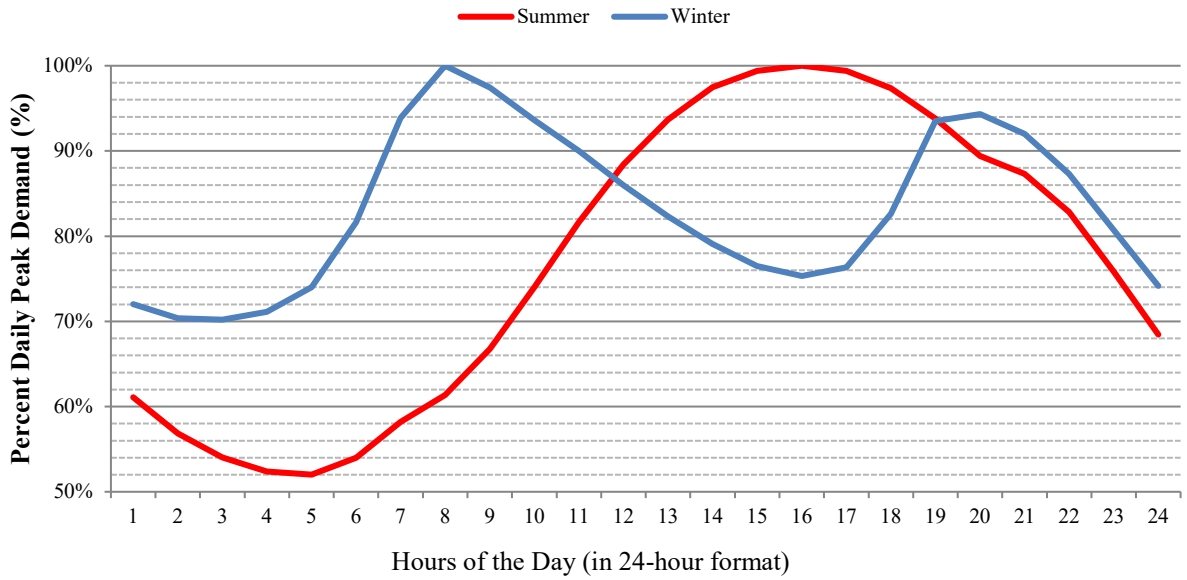
Figure 7: National - 20 Year Average Climate Data by State (Continental U.S.)



Source: U.S. National Oceanic and Atmospheric Administration Data

Seasonal weather patterns are therefore a primary factor, with peak demands calculated separately for the summer and winter periods annually, based on increased usage to meet home cooling (summer) and heating (winter) demand. Figure 8 illustrates a daily load curve for a typical day for each season. In summer, air-conditioning needs increase throughout the day, climbing steadily until a peak is reached in the late afternoon and then declining into the evening. In winter, electric heat and electric water heating produce a higher base level of usage, with a spike in the morning and an additional spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

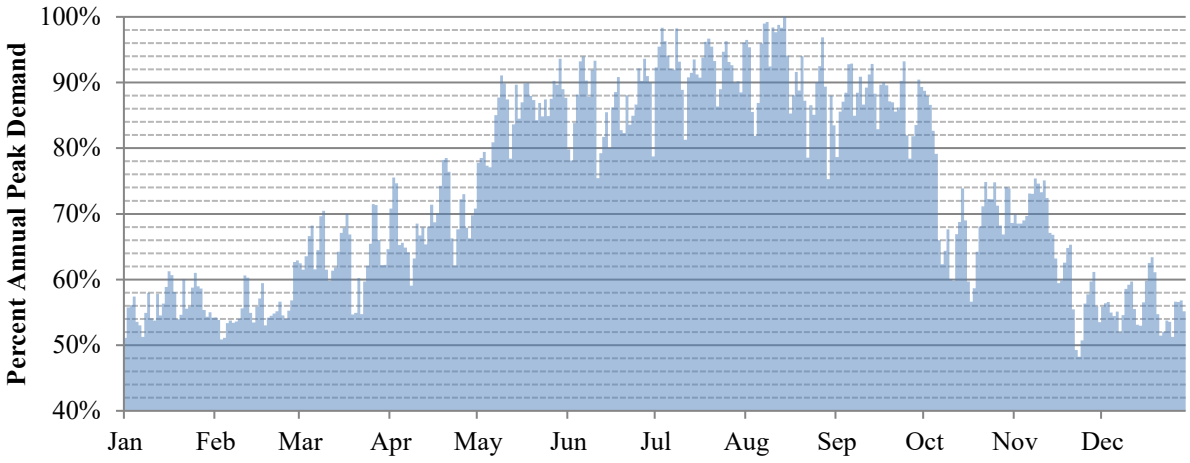


Source: TYSP Utilities' Data Responses

Florida is typically a summer-peaking state, meaning that the summer peak demand generally exceeds winter peak demand, and therefore controls the amount of generation required. Higher temperatures in summer also reduce the efficiency of generation, with high water temperatures reducing the quality of cooling provided, and can sometimes limit the quantity as units may be required to operate at reduced power or go offline based on environmental permits. Conversely, in winter, utilities can take advantage of lower ambient air and water temperatures to produce more electricity from a power plant.

As daily load varies, so do seasonal loads. Figure 9 shows the 2024 daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near annual peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

Figure 9: TYSP Utilities - Daily Peak Demand (2024 Actual)



Source: 2025 TYSP Utilities' Data Responses (Investor-Owned Utilities Only)

Florida's utilities assume normalized weather in forecasts of peak demand. During operation of their systems, they continuously monitor short-term weather patterns. Utilities adjust maintenance schedules to ensure the highest unit availability during the utility's projected peak demand, bringing units back online if necessary or delaying maintenance until after a weather system has passed.

Electric Vehicles

Other trends that may impact customer peak demand and energy consumption are also examined by utilities, including new sources of energy consumption, such as EVs. The reporting TYSP Utilities estimate approximately 576,550 plug-in EVs will be operating in Florida by the end of 2025. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 5, 2025, at 18.88 million,

resulting in an approximate 3.05 percent penetration rate of electric vehicles, up from 2.30 percent last year.[4]

TYSP Utilities' projections of EV ownership, public charging stations, and impacts to their electric grid are summarized in Table 2. Florida's electric utilities anticipate continued growth in the EV market, albeit at a somewhat reduced rate from last year, with EV ownership anticipated to increase to 4,420,779 EVs operating within the reporting utilities' electric service territories by the end of 2034. While approximately 40,000 charging stations are estimated to be available across the state by the end of 2025, more than 266,000 charging stations are anticipated by 2034. The projected EV charging station amounts listed in Table 2 include both normal and "quick-charge" public charging stations.[5] EV annual energy consumption is expected to increase from 0.9 percent of retail energy sales in 2024 to 6.5 percent by 2034.

Table 2: TYSP Utilities - Electric Vehicle Projections

Year	EVs	EV Charging Stations	Grid Impacts		
			Annual Energy	Summer Peak	Winter Peak
	(-)	(-)	(GWh)	(MW)	(MW)
2025	576,550	39,887	2,109	401.5	166.9
2026	793,136	52,121	2,942	561.1	234.4
2027	1,054,941	69,641	3,983	763.8	316.7
2028	1,370,720	90,453	5,243	1,002.9	417.4
2029	1,744,984	115,023	6,743	1,290.7	536.5
2030	2,175,781	136,453	8,480	1,624.1	678.2
2031	2,670,121	167,087	10,561	2,029.9	846.4
2032	3,220,237	195,490	12,930	2,492.7	1,041.7
2033	3,805,844	230,430	15,367	2,980.4	1,243.0
2034	4,420,779	266,575	17,945	3,487.0	1,457.3

Source: TYSP Utilities' Data Responses

A major factor driving EV growth in this state is reduced range anxiety due to the rapid expansion of charging infrastructure, with the reporting utilities projecting approximately 40,000 charging stations to be available by year-end 2025. Government agencies, private entities, municipalities, and electric utilities continue to work together to expand charging infrastructure throughout the state to meet this expected growth in EVs.

In order to prepare and accommodate for the increase in EV ownership, several utilities now offer programs or tariffs applicable to EV customers. While the nature of these programs/tariffs vary among utilities, many include Time-of-Use rates, rebates on certain charging station installations, and programs designed to increase general outreach, education, and awareness of the EV market. The Commission will continue to closely monitor the status of the EV industry to ensure it is prepared to address any regulatory issues related to the future energy and demand impacts of EVs in Florida.

[4] Florida Department of Highway Safety and Motor Vehicles January 2025 Vehicle and Vessel Reports and Statistics.
[5] "Quick-charge" public EV charging stations are those that require a service drop greater than 240 volts and/or use three-phase power.

Data Centers

Existing Data Centers

The TYSP Utilities reported that there are some data centers currently in operation, as shown in Table 3. These existing data centers are relatively small, are being served by existing generation, and have no known negative impacts on reliability.

Table 3: TYSP Utilities - Data Centers by Utility

	Existing Data Centers*			
	No. of Data Centers	Total Energy Usage in 2024 (GWhs)	Impact to Summer Peak Demand (MWs)	Impact to Winter Peak Demand (MWs)
FPL	62	283.0	30.2	30.2
DEF	5	48.0	14.5	7.0
TECO	14	71.4	11.0	10.5
JEA	4	38.1	6.3	6.2
LAK	1	4.1	---	---
Total	86	444.6	62.0	53.8

* FMPA, GRU, OUC, SEC and TAL did not report any existing data centers.
Source: TYSP Utilities' data request responses.

As general practice, utilities currently do not separately identify data centers. FPL, for example, identified existing accounts associated with data centers through a web search of companies performing that service and then matched those companies to FPL records.

Emerging Data Centers

Most of the TYSP Utilities reported that they have received inquiries from potential new large-scale data centers. Some of these utilities have included the potential data center-related load requirements in their respective TYSPs. The scale of energy and demand use of such customers is much larger than the data centers the utilities reported are currently in operation. According to a 2025 report published by Electric Power Research Institute, titled "Grid Flexibility Needs and Data Center Characteristics," data centers range from small to large, or hyper-scale, with larger data centers having a greater impact on system-wide demand and flexibility needs.

FPL believes there is a potential for customers with significant new load requirements to be served beginning in 2028 and has included a projection of these additions in its forecasts through 2034. FPL has projected that the data center peak demand and total energy usage would grow, respectively, from 172 MW and 1,281 GWh in 2028 to 732 MW and 5,450 GWh in 2034.

Similar to FPL, DEF has received inquiries from a number of potential new customers, but the Utility indicated that none of these inquiries have progressed to the level of commitment that would warrant inclusion in the DEF 2025 TYSP load forecast. Meanwhile, TECO's 2025 TYSP does not include projections of the large data centers loads due to no firm end-use customer commitments. JEA stated that it has received numerous data center inquiries over the past year and that in order to serve them, JEA would need to construct more generating resources. OUC stated that it

anticipates having discussions with potential data centers to better understand the timing and magnitude of such new loads. Similarly, SEC reported that there has been increasing interest by data centers and developers in several member service territories. As such, SEC, as the generation provider to its member cooperatives, has begun issuing quarterly surveys with each member to identify potential new large loads.

Large data centers are unique types of energy consumption sources, given their significant and constant load requirements and the potential for high costs to extend service to them. Many of the potential issues associated with serving such customers will be directly related to the size and scope of the specific data center project in question. Any necessary system upgrades to accommodate incremental load, along with the deployment of generation resources to safely and reliably serve existing and new load, are also important concerns that must be addressed. Florida utilities recognize the associated substantial increase in load to serve such customers, and to the extent such loads materialize, they will require significant new infrastructure in both generation and transmission. As such, the TYSP Utilities are actively assessing the potential impact of load growth driven by the advent of large data centers, including protections to their existing customers from the risks associated with potential stranded costs incurred to install new or upgraded facilities to serve a new large data center.

Demand-side Management (DSM)

Florida's electric utilities also consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include turning off lights and fans in unoccupied rooms, increasing thermostat settings during the summer, and purchasing appliances that exceed efficiency standards. While a certain portion of customers will engage in these activities without incentives due to economic, aesthetic, or environmental concerns, other customers may lack information or require additional incentives. Demand-Side Management (DSM) programs represents an area where Florida's electric utilities can empower and educate its customers to make choices that reduce peak load and annual energy consumption.

Florida Energy Efficiency and Conservation Act (FEECA)

In 1980, the Florida Legislature passed the Florida Energy Efficiency and Conservation Act (FEECA), which is codified in Sections 366.80 through 366.83, F.S., and Section 403.519, F.S. Under FEECA, the Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, known as the FEECA Utilities.[6] Of the TYSP Utilities, these include the three investor-owned electric utilities, FPL, DEF, TECO, and two municipal electric utilities, JEA and OUC, and together represent approximately 86 percent of 2024 retail electric sales reported in the state. The FEECA Utilities offer DSM programs for residential, commercial, and industrial customers. Energy audit programs are designed to provide an overview of customer energy usage and to evaluate conservation opportunities, including behavioral changes, low-cost

[6] FEECA also applies to Florida Public Utilities Company (FPUC), a non-generating investor-owned electric utility. As FPUC purchases power from other generating entities and does not own or operate its own generation resources, it is not required to file a TYSP.

measures customers can undertake themselves, and participation in utility-sponsored DSM programs.

In 2024, the Commission held a hearing and established goals for each of the FEECA Utilities for the period 2025 through 2034. In 2025, the Commission reviewed and approved DSM Plans for each FEECA electric utility designed to meet its goals. The Commission is scheduled to have its next goalsetting proceeding no later than 2029 for the period 2030 through 2039.

DSM Programs

DSM programs are generally divided into three categories: interruptible load, load management, and energy efficiency. The first two are considered dispatchable, and are collectively known as demand response, meaning that the utility can call upon them during a period of peak demand or other reliability concerns, but otherwise they are not utilized. In contrast, energy efficiency measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible load is achieved through the use of agreements with large customers to allow the utility to interrupt the customer's load, reducing the generation required to meet system demand. Interrupted customers may use back-up generation to fill their energy needs, or cease operation until the interruption has passed. A subtype of interruptible load is curtailable load, which allow the utility to interrupt only a portion of the customer's load. In exchange for the ability to interrupt these customers, the utility offers a discounted rate for energy or other credits which are paid for by all ratepayers.

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak. As of 2025, the total amount of demand response resources available for reduction of peak load is 3,345 MW for summer peak and 3,127 MW for winter peak. Demand response is anticipated to increase only marginally to approximately 3,412 MW for summer peak and 3,157 MW for winter peak by 2034. Residential load management is anticipated to decline slightly, while interruptible load is level and commercial/industrial demand response has a slight increase.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and high efficiency appliances, customers can reduce both peak demand and annual energy consumption, resulting in lower energy bills. DSM programs work in conjunction with building codes and appliance efficiency standards to increase energy savings

above the minimum required by local, state, or federal regulations. As of December 31, 2024, energy efficiency is responsible for peak load reductions of 4,732 MW for summer peak and 4,447 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,731 MW for summer peak and 5,231 MW for winter peak by 2034.

Forecast Load and Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated in Figure 10. The forecasts shown below are based upon normalized weather conditions, while the historic demand and energy values represent the actual impact of weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in the summer and electric heating in the winter, so both seasons experience a great deal of variability due to severe weather conditions.

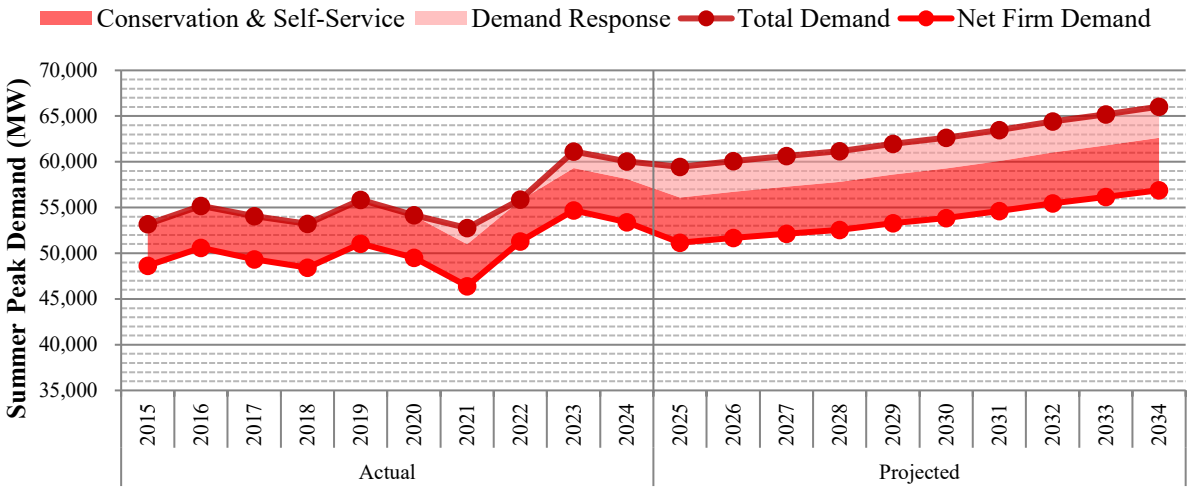
DSM, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities.

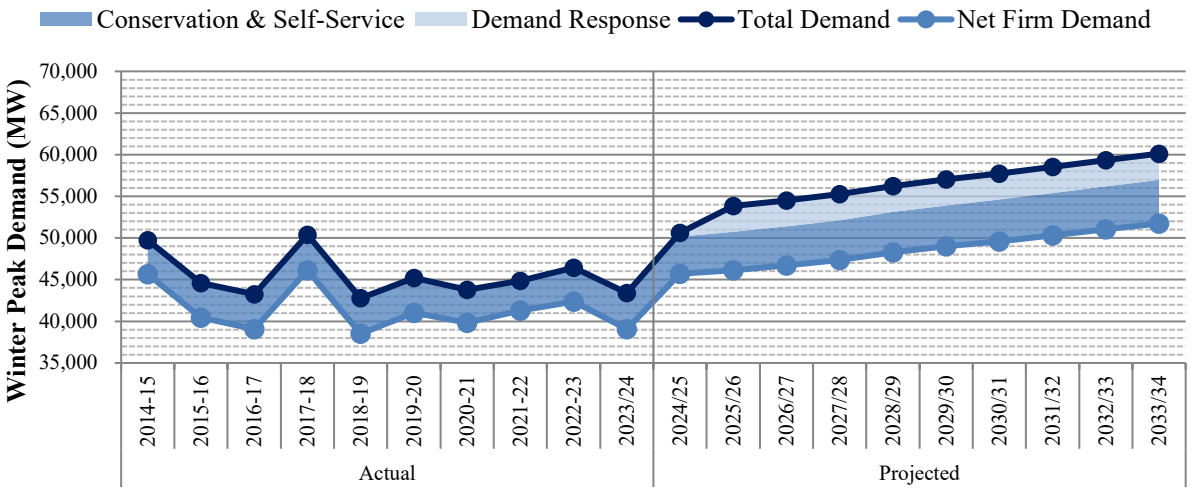
Demand response is included in Figure 10 in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount of demand response that was available at the time. Overall, demand response has only been partially activated, as sufficient generation resources were available during the annual peak. Residential load management has been utilized to a limited extent during peak periods, with even less interruptible load being activated.

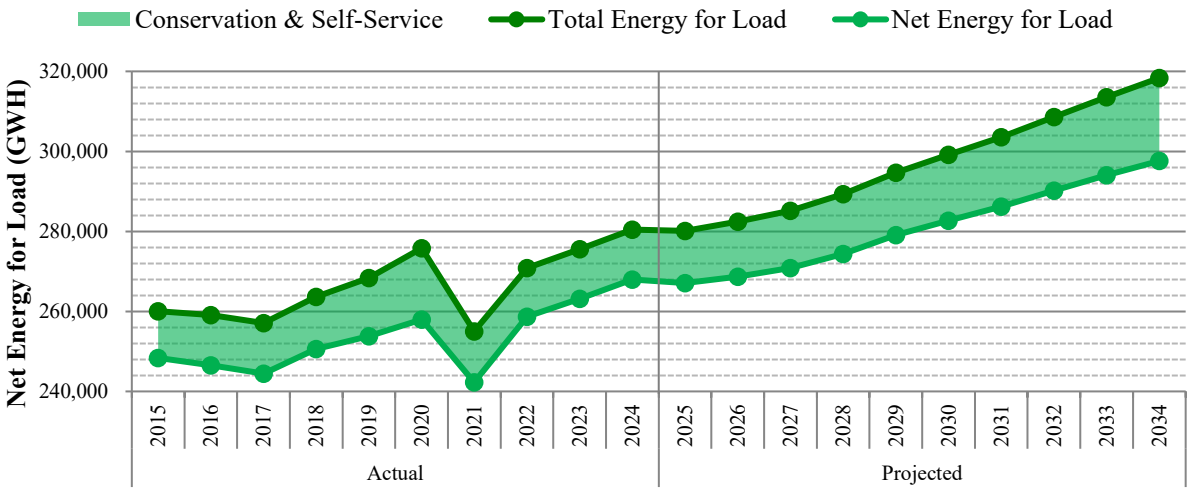
For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on future operating conditions, if an electric utility has sufficient generating capacity and it is economical to serve all customers loads, demand response would likely be inactive or only partially activated.

As previously discussed, Florida is normally a summer-peaking state and has been for the past 10 years. This trend is anticipated to continue, with the next 10 forecasted years all anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities anticipate a gradual increase in both summer and winter net firm demand during the planning period.

Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy







Source: FRCC 2025 Regional Load and Resource Plan

Forecast Methodology

Load forecasting is an essential requirement of all electric utility companies for purposes of system planning. In order for utilities to reliably and cost-effectively serve their respective customers, they must be able to accurately determine their energy and demand requirements. Thus, the load forecast function facilitates the ongoing balance between system demand and system supply.

Load forecasting can be divided into three types depending on the forecasting horizon: short-, medium-, and long-term. Short-term load forecasting denotes forecast horizons of up to one week ahead. Medium-term load forecasting ranges from one week to one year ahead. Long-term load forecasting typically targets forecast horizons of one to 10 years, and sometimes up to several decades. Long-term load forecasting provides the essential load requirement data that a utility must have in order to effectively modify its system of generation, transmission, and distribution assets. Load forecasts directly impact the timing, type, and location of asset expansions, replacements, and retirements. Hence, the load forecast function plays a vital role in an electric utility's system planning and, in Florida, serves as the foundation of a utility's TYSP.

Florida's electric utilities perform long-term forecasts of peak demand and annual energy sales using various forecasting models, including econometric and end-use models, and other forecasting techniques such as surveys. In the development of econometric models, the utilities use historical data sets including dependent variables (e.g., winter and summer peak demand per customer, residential energy use per customer) and independent variables (e.g., peak day minimum temperature, real personal income, heating degree days and cooling degree days, etc.) to infer relationships between the two types of variables. These historical relationships, combined with available forecasts of the independent variables and the utilities' forecasts of customers, are then used to forecast the peak demand and energy sales. For some customer classes, such as industrial customers, surveys may be conducted to determine the customer's specific expectations for their own future electricity consumption.

Forecasting models for energy sales are prepared by revenue class (e.g., residential, small and large commercial, small and large industrial, etc.). Commonly, the results of the models must be adjusted to take into account exogenous impacts, such as the impact of the recent growth in EV and distributed generation. The forecasting models for energy sales must also take into account DSM.

Another type of forecasting model, sometimes used to project energy use in conjunction with econometric models, is an "end-use model." These models can capture trends in appliance and equipment saturation and efficiency, as well as building size and thermal efficiency, on customers' energy use. If such end-use models are not used, the econometric models for energy often include an index comprised of efficiency standards for air conditioning, heating, and appliances, as well as construction codes for recently built homes and commercial buildings.

Florida's electric utilities rely upon data that is sourced from public and private entities for historic and forecast values of specific independent variables used in econometric modeling. Public resources such as the University of Florida's Bureau of Economic and Business Research, which provides county-level data on population growth, and the U.S. Department of Commerce's Bureau of Labor Statistics, which publishes the Consumer Price Index, are utilized along with private forecasts for economic growth from macroeconomic experts, such as Moody's Analytics. By

combining historic and forecast macroeconomic data with customer and climate data, Florida's electric utilities project future load conditions.

Historically, the various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry; and each utility has developed its own individualized approach to project load. The models have relied upon dependent and independent variable data to project energy sales and demand amounts that exist within a probabilistic range. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and cost-effectively. Again, for the 2025 TYSPs, Florida's electric utilities used these same types of models and techniques to prepare their forecasts.

Accuracy of Retail Energy Sales Forecast

For each reporting TYSP Utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for the Commission's review involves comparing actual retail energy sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2024 retail energy sales were compared to the forecasts made in 2019, 2020, and 2021. The resulting differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy by applying a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast. For the 2025 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2015 through 2024 to forecasts made between 2006 and 2020. These are summarized in Table 4.

Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts
(Five-Year Rolling Average)*

TYSP Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2016	2015 - 2011	2011 - 2006	12.5%	12.5%
2017	2016 - 2012	2012 - 2007	9.1%	9.1%
2018	2017 - 2013	2013 - 2008	6.0%	6.0%
2019	2018 - 2014	2014 - 2009	3.5%	3.5%
2020	2019 - 2015	2015 - 2010	2.1%	2.3%
2021	2020 - 2016	2016 - 2011	1.6%	2.0%
2022	2021 - 2017	2017 - 2012	1.0%	1.6%
2023	2022 - 2018	2018 - 2013	(0.1%)	1.4%
2024	2023 - 2019	2019 - 2014	(1.0%)	1.6%
2025	2024 - 2020	2020 - 2015	(1.8%)	2.0%

Source: 2006-2025 TYSPs
* Inputs used including utilities' revisions to the corresponding prior TYSP-reported actual and/or projected data.

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine, with more detail, the source of high error rates in terms of forecast timing. Table 5 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of a three to five-year period that was also used in the analysis in Table 4.

As displayed in Table 5, the TYSP Utilities' retail energy sales forecasts show large positive error rates during the recession-impacted period 2012 through 2015. Starting in 2015, the error rates have declined considerably and the error rates calculated based on recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2012 - 2014 sales forecasts. Most of the last five years' four-year ahead, three-year ahead, two-year ahead, and one-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, the last three years' six-year ahead and five-year ahead forecasts all render negative error rates as well. Note that all of the 2022-, 2023-, and 2024-related forecasts made between one to six years prior show relatively higher negative error rates. This is due to the respective annual retail energy sales achieved which is largely attributable to the very hot weather Florida experienced in the recent years.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)*

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2012	26.4%	26.1%	23.2%	8.6%	4.0%	3.8%	19.3%	19.3%
2013	28.6%	26.3%	10.0%	6.0%	5.6%	3.0%	14.1%	14.1%
2014	27.2%	9.7%	6.0%	5.6%	2.7%	2.1%	7.1%	7.1%
2015	7.2%	3.5%	3.1%	0.9%	(0.1%)	(1.3%)	2.5%	2.5%
2016	4.2%	4.3%	2.2%	1.1%	0.1%	(1.1%)	2.5%	2.5%
2017	6.9%	4.8%	3.5%	2.4%	1.5%	(0.2%)	3.6%	3.6%
2018	4.2%	2.7%	1.6%	0.6%	(1.3%)	(1.2%)	1.6%	1.6%
2019	2.8%	1.9%	0.8%	(1.4%)	(1.4%)	(2.0%)	0.4%	1.3%
2020	2.4%	1.3%	(1.0%)	(1.1%)	(1.9%)	(1.2%)	(0.3%)	1.1%
2021	2.6%	0.4%	0.0%	(0.8%)	(0.1%)	0.0%	(0.2%)	0.4%
2022	(1.6%)	(1.9%)	(2.9%)	(2.2%)	(2.1%)	(3.1%)	(2.3%)	2.3%
2023	(2.1%)	(3.3%)	(2.7%)	(2.5%)	(3.2%)	(2.6%)	(2.8%)	2.8%
2024	(3.9%)	(3.3%)	(3.3%)	(3.7%)	(3.2%)	(3.2%)	(3.4%)	3.4%

Source: 2006-2025 TYSPs

* Inputs used include utilities' revisions to the corresponding prior TYSP-reported actual and/or projected sales data.

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2024 in Table 5. However, all the major global and domestic events (e.g., the Russia-Ukraine war, intense conflicts in the Middle East, increased tariffs on foreign countries, supply chain issues, potential factors such as recession, increases in inflation rates, pandemic, etc.), individually or collectively, could inflict damage to the U.S. economy. As such, there remains

uncertainty as to what the economic impacts of such events will be going forward. Therefore, the actual retail energy sales over the next few years could differ from what Florida utilities projected in 2024 and earlier years. Consequently, average forecasted energy sales error rates during this period may deviate from the relatively low levels recorded since 2015. It is important to recognize that the dynamic nature of the economy, the weather, and even global health, political and economic issues present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of retail energy sales forecasts.

Renewables and Energy Storage

Pursuant to Section 366.91, F.S., the Legislature has found that it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(e), F.S., defines renewable energy in part, as follows:

> "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced or resulting from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power.

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes to provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. Section 366.91(2)(e), F.S., includes the following language which recognizes the aforementioned cogeneration process:

> The term [Renewable Energy] includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 14,723 MW of firm and non-firm generation capacity, which represents 20 percent of Florida's overall generation capacity of 73,500 MW in 2024. Table 6 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	13,311	90.4%
Municipal Solid Waste	473	3.2%
Biomass	380	2.6%
Waste Heat	173	1.2%
Wind	272	1.8%
Landfill Gas	64	0.4%
Hydroelectric	51	0.3%
Renewable Total	**14,723**	

Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Of the total 14,723 MW of renewable generation, approximately 5,145 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fuel power plants. Solar generation contributes approximately 4,706 MW to this total, based upon the

coincidence of solar generation and summer peak demand, or about 35 percent of its installed capacity. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

Of the 1,412 MW of non-solar generation, only 439 MW is treated as firm because of contractual commitments. The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida's utilities.

Utility-Owned Renewable Generation

Most renewable generation in Florida is utility-owned, with 9,988 MW of installed capacity, or 67.8 percent of total renewables, consisting primarily of solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 9,831 MW of existing utility-owned solar capacity, approximately 4,485 MW, or about 45.6 percent, is considered firm. All other renewable sources account for an additional 157 MW of utility-owned generation, which are all considered firm.

Non-Utility Renewable Generation

Approximately 1,934 MW, or 13.1 percent, of Florida's existing renewable capacity comes from non-utility generators such as cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). In 1978, the U.S. Congress enacted the Public Utility Regulatory Policies Act (PURPA), which requires utilities to purchase electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides, in part, that:

> A utility's "full avoided costs" are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

If a renewable energy generator meets specified deliverability requirements, its capacity and energy output can be compensated under a firm contract. Rule 25-17.250, F.A.C., requires each investor-owned utility to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's TYSP. In order to promote renewable energy generation, the Commission requires the investor-owned utilities to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits their financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not

required. As-available energy is purchased at a rate equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer-Owned Renewable Generation

Approximately 2,794 MW, or 19.0 percent, of renewable capacity is from small customer-owned renewable systems. As of the end of 2024, over 292,284 systems have been installed statewide. With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar. Non-solar generation, which accounts for only 25 installations and 7.1 MW of installed capacity includes wind turbines and anaerobic digesters.

Table 7: State of Florida - Customer-Owned Renewable Growth

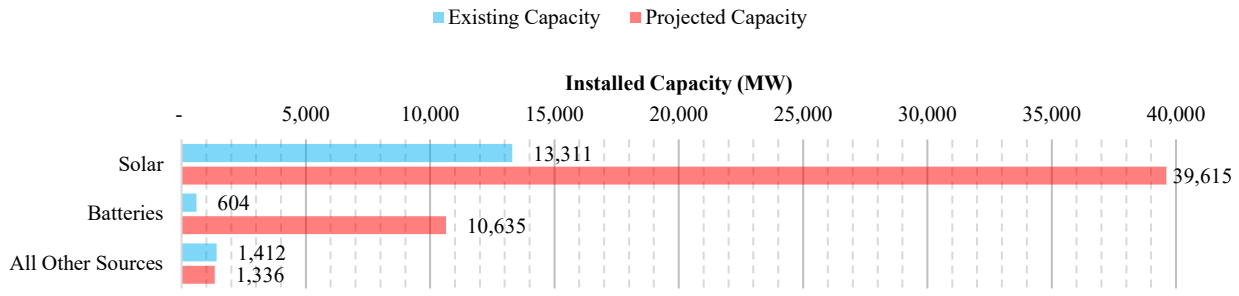
Year	2018	2019	2020	2021	2022	2023	2024
Number of Installations	37,862	59,508	90,552	130,947	189,952	249,521	292,284
Installed Capacity (MW)	317	514	835	1,177	1,780	2,351	2,801

Source: 2018-2024 Net Metering Reports

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 26,228 MW over the 10-year planning period, a decrease from last year's estimated 30,737 MW projection. Solar generation, primarily utility-owned, is the sole renewable type projected to increase over the planning horizon, with non-solar renewables decreasing by 76 MW due to retirements or expired contracts. While solar generation is covered under the Florida Electrical Power Plant Siting Act, all future solar projects are below the 75 MW threshold, and therefore are not required to seek approval from the Commission prior to construction. Figure 11 summarizes the existing and projected renewable capacity by generation type as well as energy storage capacity in the form of batteries.

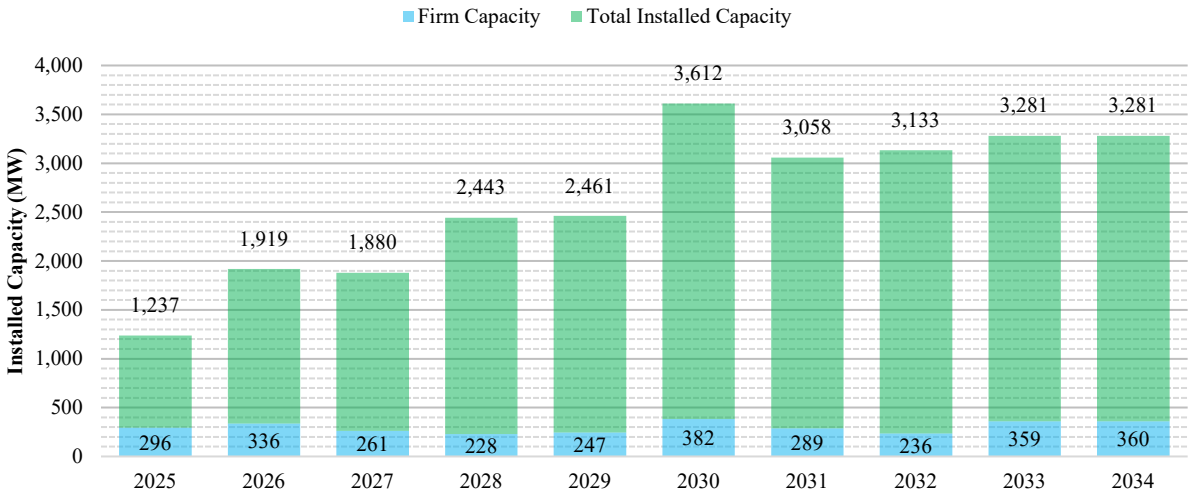
Figure 11: State of Florida – Current and Projected Renewables and Energy Storage



Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As noted previously, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 26,304 MW to be installed, excluding solar degradation. This consists of 23,311 MW of utility-owned solar and 2,993 MW of contracted solar. The firm contribution of solar varies by utility, with some having a set percentage value for all projects over the planning period, and others having a declining value as projects are added. A total of 3,032 MW of solar additions are considered firm for summer peak, or about 11.4 percent of the total installed. Figure 12 provides an overview of the additional solar capacity generation planned within the next 10 years, as well as the amount considered firm for summer reserve margin planning.

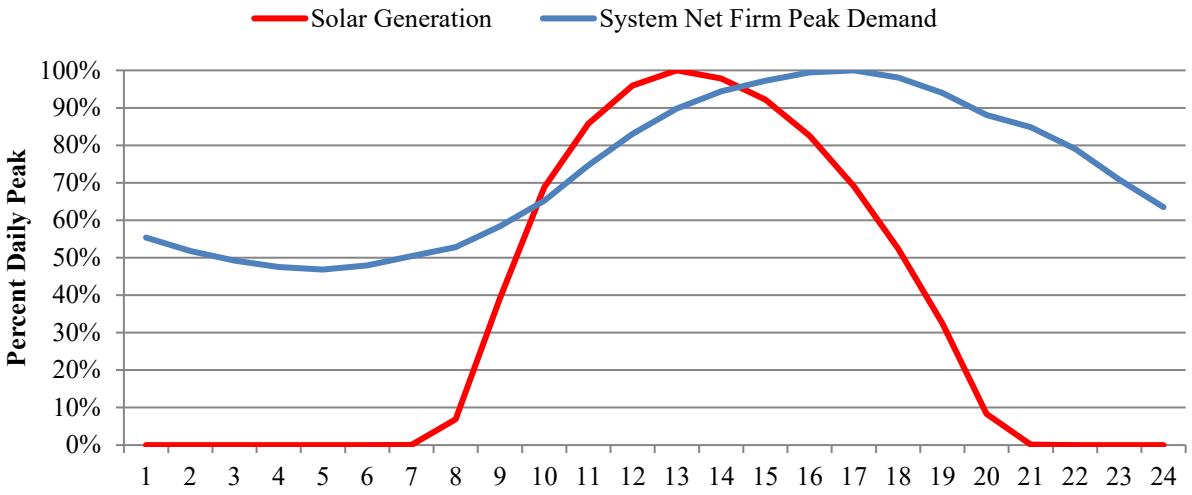
Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As the amount of solar increases in the state, the difference in how it operates compared with traditional generation will become increasing important to the grid. Solar generation cannot be dispatched on demand; instead, it is produced based on conditions at the plant site, which are influenced by variations in daylight hours, cloud cover, and other environmental factors. Generally speaking, the peak hours for production of a solar facility are closer to noon, whereas the peak in system demand tends to be in the early evening in summer and early morning in winter. Figure 13 illustrates this with example data from FPL's 2023 TYSP hourly dispatch model for their 2024 summer peak day. While solar generation peaks at 1:00 p.m., the net firm system demand peaks at 5:00 p.m. when solar generation is only at 69 percent of its daily peak. By 6:00 p.m., demand remains high, at 98 percent of its daily peak, while solar generation falls to 52 percent. Energy storage and other technologies to shift load, such as DSM programs or demand response, can be used to offset these characteristics.

Figure 13: FPL 2024 Summer Peak Day Hourly Dispatch



Source: 2023 FPL Data Response

Energy Storage

In addition to a number of electric grid-related applications, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well. Energy storage technologies that are currently under research include pumped hydropower, flywheels, compressed air, thermal storage, and battery storage. Of these technologies, battery storage is primarily planned and used by utility companies. Battery storage has been proposed for connection directly to the grid, behind the meter box (net metering) or integrated with a solar/PV unit. Battery storage technology has continued to advance, and the cost of storage is projected to continue to decline over the long-term, aided, in part, by continued tax credits from the Inflation Reduction Act.

Florida's utilities have engaged in small pilot programs to determine the best placement and usage for energy storage technologies, including behind the customer's meter, at distribution substations, and at generating facilities. Each use case has its own benefits, allowing customers to ride out outages (net metering), improving reliability and reducing line losses (distribution substations), or providing firm capacity to the grid (generating facilities). Currently, the TYSP Utilities have 604 MW of installed battery energy storage, with the single largest installation being FPL's 409 MW Manatee battery storage site. Battery storage is a unique resource in that it can contribute to firm capacity and offers a fast ramp rate, but it has a limited duration and requires charging from the grid, becoming a load to be served rather than generation serving load. Due to small inefficiencies in charging and discharging, batteries actually increase the total amount of energy that utilities must produce to serve customer load — affecting net load rather than net generation.

Over the next decade, utilities anticipate adding approximately 10,031 MW of energy storage, primarily directly on the transmission system or a specific power plant. While energy storage provides firming for intermittent solar facilities, grid connected batteries will not be restricted to charging from renewable sources. These units can be charged from any energy source during off-peak periods, including fossil fuel generation. To the extent solar generation is charging batteries

it is also not offsetting fossil fuel generation that otherwise would be occurring on the grid during the same period. Some energy storage will be directly connected to a specific renewable power plant. Given these characteristics, for reliability planning purposes, 548 MW of existing battery storage and 5,673 MW for planned battery storage is considered firm for summer peaks.

Companies are continuing to explore different forms of energy storage even as they expand their construction of battery storage, such as storage with longer duration or superior ability to address operational needs. The Commission will continue to monitor technological developments in energy storage to cost-effectively address the state's fuel diversity, reducing the dependence on fossil fuels, while still maintaining adequate resources to provide for customer loads.

Traditional Generation

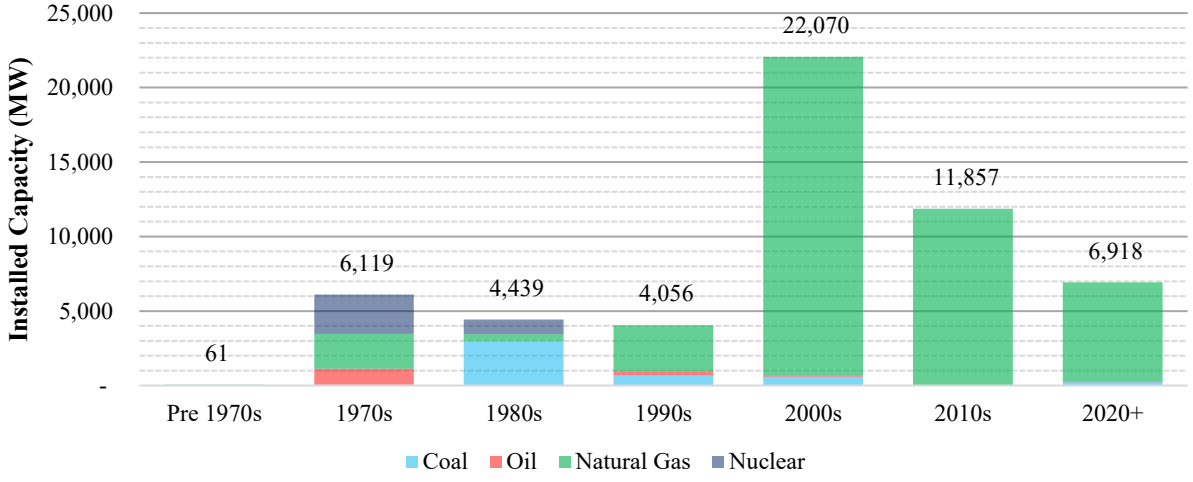
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. Due to forecasted increases in peak demand, further traditional resources are anticipated over the planning period.

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Previous to the oil embargo, Florida used oil-fired generation as its primary source of electricity until the increase in oil prices made this undesirable. Since that time, Florida's electric utilities have sought a variety of other fuel sources to diversify the state's generation fleet and more reliably and cost-effectively serve customers. Numerous factors, including swings in fuel prices, availability, environmental concerns, and other factors have resulted in a variety of fuels powering Florida's electric grid. Solid fuels, such as coal and nuclear, increased during the shift away from oil-fired generation, and more recently natural gas has emerged as the dominant fuel type in Florida.

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's traditional generating units is 22 years. While the original commercial in-service date may be in excess of 50 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 14 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 14: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2025 Regional Load and Resource Plan

The existing generating fleet will be impacted by several events over the planning period. New and proposed environmental regulations may require changes in unit dispatch, fuel switching, or installation of pollution control equipment which may reduce net capacity. Modernizations will allow more efficient resources to replace older generation, while potentially reusing power plant assets such as transmission and other facilities, switching to more economic fuel types, or implementing uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be operated and maintained economically or that fail to meet environmental requirements will reduce existing generation.

Impact of the EPA Rules

Over the summer, the EPA has issued three proposed rules that, if finalized and implemented as proposed, would significantly change the current environmental regulatory landscape affecting energy generation.

On June 11, 2025, the EPA Administrator announced a proposal to repeal all greenhouse gas (GHG) emission standards for electric generating units (EGUs) under Section 111 of the Clean Air Act. The EPA argues that GHG emissions from these facilities do not contribute significantly to dangerous air pollution.

Also on June 11, 2025, the EPA announced a proposal to repeal amendments to the 2024 Mercury and Air Toxics Standards that directly result in coal-fired power plants shutting down. The MATS Proposed Rule seeks to repeal recent amendments that tightened filterable particulate matter emission standards and mercury emission standards for certain existing coal-fired EGUs that use lignite, instead of bituminous coal. There are no lignite coal-firing units in Florida at this time. This proposal would reverse three key regulatory changes: the stricter filterable particulate matter emission standard for existing coal-fired EGUs, the more restrictive compliance demonstration requirements that limited monitoring options to only particulate matter continuous emission monitoring systems, and the tightened mercury emission standard for lignite-fired EGUs.

On July 29, 2025, the EPA issued a proposal to rescind the 2009 Endangerment Finding, which would have sweeping effects on GHG regulations for the transportation sector. If finalized, the proposal would repeal all GHG emission regulations for motor vehicles and engines. The Endangerment Finding Proposed Rule could also undermine the legal basis for GHG regulations across the power sector.

Modernization and Efficiency Improvements

Modernizations involve removing existing generator units that may no longer be economical to operate, such as oil-fired steam units, and reusing the power plant site's transmission or fuel handling facilities with a new set of generating units. The modernization of existing plant sites, allows for significant improvement in both performance and emissions, typically at a lower price than new construction at a greenfield site. Not all sites are candidates for modernization due to site layout and other concerns, and to minimize rate impacts, modernization of existing units should be considered along with new construction at greenfield sites.

Several utilities have converted oil-fired and coal-fired steam units to natural gas-fired combined cycle units, or converted or upgraded them to run on natural gas for all or a majority of their fuel.

This trend continues, with direct coal-fired steam to natural gas-fired steam, such as OUC's conversion of Stanton Unit 2 by 2027. Additional planned conversions from coal or other solid fuels are planned by the TYSP Utilities, including TECO's conversion of the Polk Unit 1 integrated gasification combined cycle unit, the only petcoke fueled combined cycle within the state, to a natural gas-fired combustion turbine in 2025.

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. Overall, 490 MW of additional summer firm capacity is from uprates to existing natural gas fired combined cycle units. In addition, DEF and OUC plan transmission upgrades that will allow them improved access to capacity from existing natural gas units at the Osprey and Osceola plant sites in 2025. While these do not change the amount of capacity available in the state as a whole, it improves the ability to deliver capacity where needed on the system.

Utilities are also investigating potential future conversions or dual-firing with hydrogen. For example, FPL's hydrogen pilot at its Okeechobee natural gas-fired combined cycle facility, approved as part of FPL's 2021 Settlement Agreement, involves using a solar powered electrolyzer to produce hydrogen from water and replacing up to 5 percent of the fuel mix with hydrogen in the unit's combustion turbines.[7]

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 8 lists the 3,848 MW of existing generation that is scheduled to be retired during the planning period. A majority of the retirements are coal-fired steam generators, with four units totaling 2,067 MW of capacity to be retired by 2034, followed by oil combustion turbines, with five units totaling 753 MW by 2034, and natural gas-fired steam generation, with four units totaling 750 MW of capacity to be retired by 2030.

[7] Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

Table 8: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Net Capacity (Sum MW)
Coal Steam Retirements			
2025	FMPA/OUC	Stanton Energy Center Unit 1	451
2034	FPL	Scherer Unit 3	215
2034	DEF	Crystal River 4 & 5	1,422
		Subtotal	**2,067**
Oil Combustion Turbine Retirements			
2026	DEF	Bayboro Units P1-P4	137
2027	DEF	Debary Units P2-P6	227
2027	DEF	Bartow Units P1 & P3	82
2028	FPL	Lansing Smith Unit 3A	32
2034	DEF	Intercession City P1-P6	275
		Subtotal	**753**
Natural Gas Steam Retirements			
2027	GRU	Deerhaven Unit FS01	76
2029	FPL	Gulf Clean Energy Center 4 & 5	150
2030	JEA	Northside Unit 3	524
		Subtotal	**750**
Natural Gas Combustion Turbine Retirements			
2026	FPL	Pea Ridge 1-3	12
2031	GRU	Deerhaven Unit GT1 & GT2	35
2034	DEF	Bartow Units P2 & P4	86
2034	DEF	Suwannee P1-P3	145
		Subtotal	**278**
		Total Retirements	**3,848**

Source: 2025 TYSPs

Reliability Requirements

Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted customer demand. If utilities only had sufficient generating capacity to meet forecasted peak demand, then potential instabilities could occur if customer demand exceeds the forecast, or if generating units are unavailable due to maintenance or forced outages. To address these circumstances, utilities are required to maintain additional planned generating capacity above the forecasted customer demand.

Reserve Margin

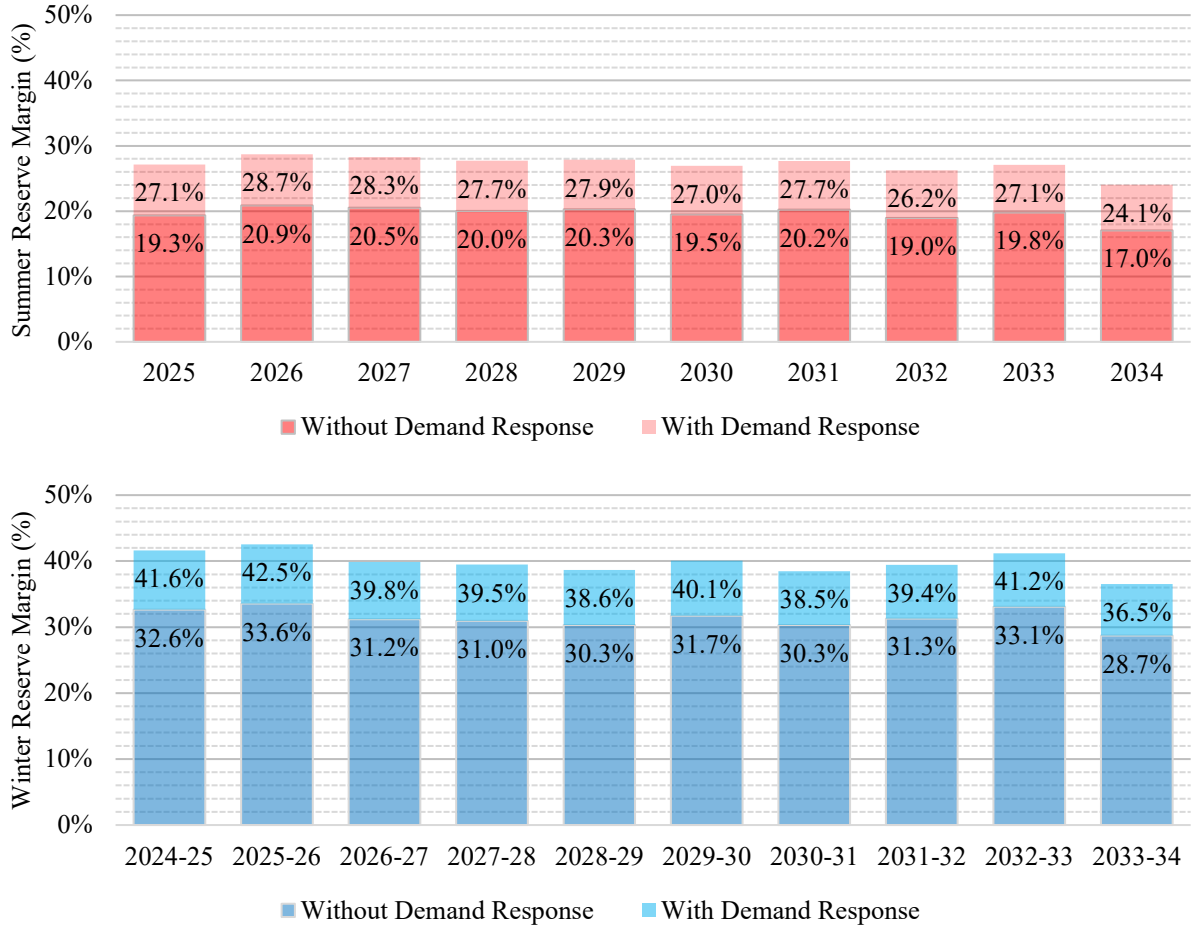
One reliability metric commonly used by the TYSP Utilities is a seasonal planning reserve margin. Each utility annually compares their forecasted seasonal peak demand after activation of demand response resources with the total amount of firm generation available at the seasonal peak hour. The difference between these values is the reserve margin, which is expressed in both megawatts and as a percentage of the net firm peak demand. Pursuant to Rule 25-6.035, F.A.C., electric utilities within Florida must maintain a minimum reserve margin of 15 percent for planning purposes, although certain utilities have elected to use a higher planning reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO,

are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.[8] As a whole, Florida typically has a lower summer reserve margin than winter, but individual utilities may be more impacted by winter peaks.

Regarding demand response, while participants receive discounted rates or credits paid for by all ratepayers regardless of activation, the concern exists that as activations increase, participation could decrease. While large interruptible customers typically have notice period requirements, small load management customers usually do not have an advanced notice requirement. Historically, activations of demand response have almost exclusively been of the smaller load management customers, and typically for off-peak periods. As illustrated in Figure 15, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin in all years. Even without demand response, the statewide reserve margin is anticipated to remain 17 percent or above throughout the planning period. On average, demand response contributes 7.5 percent toward the summer reserve margin, and 8.4 percent toward the winter reserve margin.

[8] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida*.

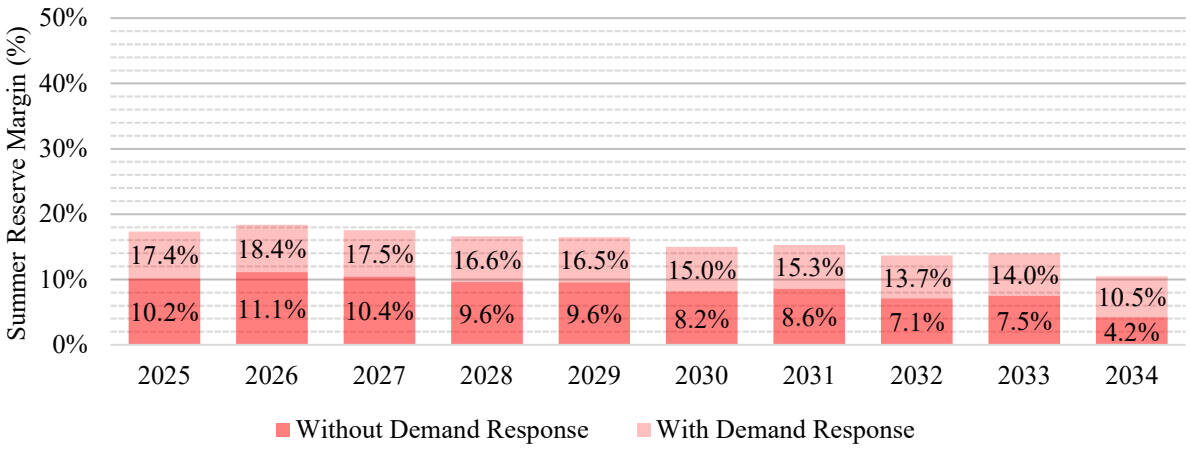
Figure 15: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2025 Regional Load and Resource Plan - Revised Form 10

As discussed above, the reserve margin calculation is based upon the hour of highest peak demand and compared to the available firm generation. With the increase in the amount of non-dispatchable generation, primarily solar, the highest peak hour may no longer represent the time of highest dispatchable generation need especially for the summer peak period. One potential approach to address this would be to evaluate a net-solar peak hour, treating solar as a reduction to load similar to demand response. Alternatively, the firm contribution of solar could be removed from the reserve margin analysis to determine the contribution only of dispatchable resources, such as demand response or traditional generation. On average, solar contributes approximately 11.7 percent towards the summer reserve margin over the planning period. As illustrated by Figure 16, even without any contribution from solar at time of system peak, the statewide reserve margin would remain above the 15 percent threshold until 2032.

Figure 16: State of Florida - Projected Summer Reserve Margin without Solar



Source: FRCC 2025 Load & Resource Plan, 2025 TYSP Data Responses

Loss of Load Probability

In addition to reserve margin, Florida's utilities have used multiple indices to determine the reliability of their electric supplies. An additional metric is the Loss of Load Probability (LOLP), which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. A maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years is a frequently used metric. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement has typically been the controlling factor for the addition of capacity for several decades.

Similar to reserve margin, with an increase in non-dispatchable generation, a LOLP analysis that looks at all days or hours of the year provides additional information regarding the reliability of the system. Based on the 2025 Load and Resource Reliability Assessment Report, the FRCC details how it conducted a statewide LOLP analysis for the period 2025 through 2029 using a system planning model that considered all hours of the year, using probabilistic methods to simulate various weather and unit outages, producing several thousand scenarios, and performing sensitivities with no imports, no demand response activations, and high load conditions. Overall, in the base case and in each sensitivity the FRCC determined that the planned resources are more than adequate to meet the 0.1 LOLP requirement by at least three orders of magnitude in the base case, and two orders of magnitude for the highest sensitivity. The results of the scenarios are provided in Table 9.

Table 9: FRCC Loss of Load Probability Study Results

Year	Scenario Results (Days/Year)			
	Base Case	No Availability of Imports	No Availability of Demand Response	High Load Case
2025	0.0001844	0.0003500	0.0007738	0.0010250
2026	0.0000514	0.0000318	0.0003046	0.0003964
2027	0.0000153	0.0000132	0.0001546	0.0002870
2028	0.0001177	0.0001135	0.0004745	0.0010767
2029	0.0002925	0.0002562	0.0014651	0.0028279

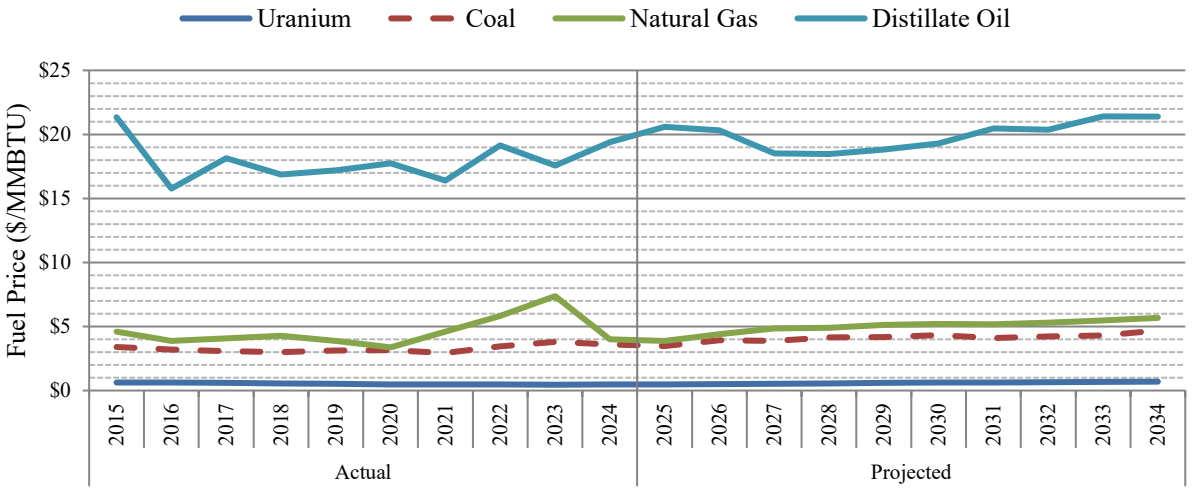
Source: 2025 TYSP Workshop FRCC Studies and Reports

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a fuel-based power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, uranium, and coal. Natural gas remains the most widely used fuel statewide, projected to account for between 73.2 percent and 58.0 percent of electric generation (in GWh) from 2025 through 2034.

As shown on Figure 17, the forecasted weighted average price per million British Thermal Units (MMBTUs) for natural gas, uranium, and coal are all expected to increase over the next 10 years. The highest forecasted increase in price over the forecast horizon is for natural gas, which is expected to increase from $3.98 per MMBTU to $6.10 per MMBTU by 2034. Meanwhile uranium, easily the lowest price fuel of the three, is projected to increase in price from $0.51 MMBTU to $0.75 MMBTU. Coal is projected to increase in price from $3.29 MMBTU to $4.78 MMBTU. Distillate oil is the most expensive fuel, with forecasted prices ranging between $17.43 and $21.24 per MMBTU from 2025 through 2034. Its high cost helps explain why it is used primarily for backup and peaking purposes.

Figure 17: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities

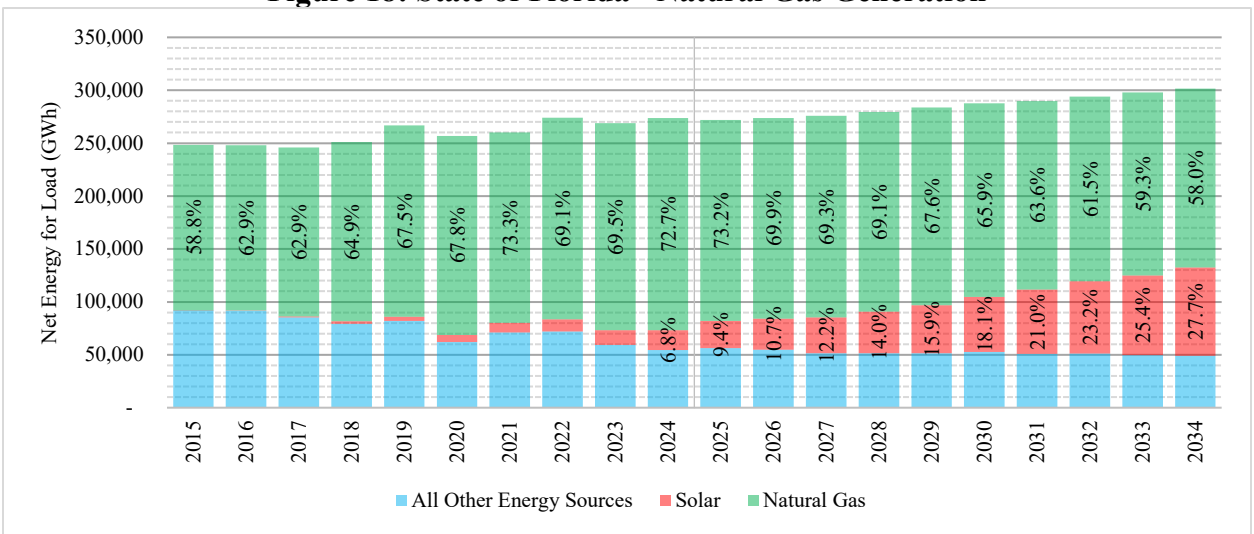


Source: TYSP Utilities' Data Responses

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida and since 2011 has generated more net energy for load than all other fuels combined. As Figure 18 illustrates, natural gas was the source of approximately 72.7 percent of electric energy consumed in Florida in 2024. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline throughout the remainder of the planning period, offset by solar generation. Solar generation is anticipated to exceed all non-natural gas energy sources combined by 2031.

Figure 18: State of Florida - Natural Gas Generation

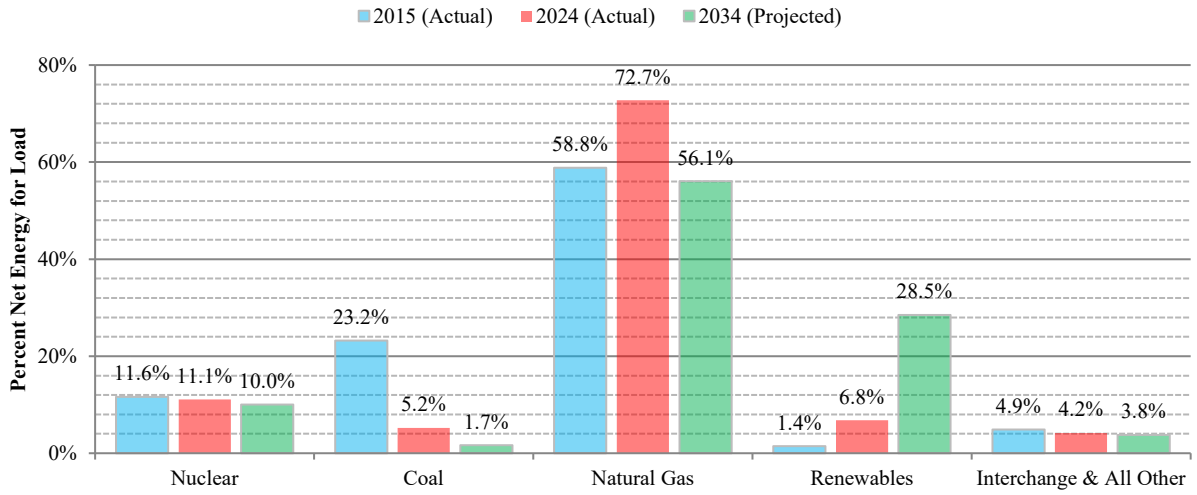


Source: FRCC 2015-2034 Regional Load and Resource Plans

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatility in fuel price fluctuations, it is important that utilities have a level of flexibility in their generation mix. Maintaining fuel diversity on Florida's system faces several difficulties. Existing coal units will require additional emissions control equipment leading to reduced output, or retirement if the emissions controls are uneconomic to install or operate. New solid fuel generating units such as nuclear and coal have long lead times and high capital costs. New coal units face challenges related to environmental compliance requirements, making it unlikely that they could be permitted without novel emissions control technologies.

Figure 19 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2015 and 2024, and forecast year 2034. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, but this trend is anticipated to slightly decrease during the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2030.

Figure 19: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2015-2034 Regional Load and Resource Plan

Based on 2023 U.S. Energy Information Administration data, Florida ranks fifth in terms of the total volume of natural gas consumed compared to the rest of the United States, representing 5 percent of national gas consumption.[9] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas, representing 10.9 percent of national gas consumption for electric generation. Approximately 86.0 percent of natural gas consumed in Florida was for electric generation in 2023. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

[9] U.S. Energy Information Administration Natural Gas Annual Report.

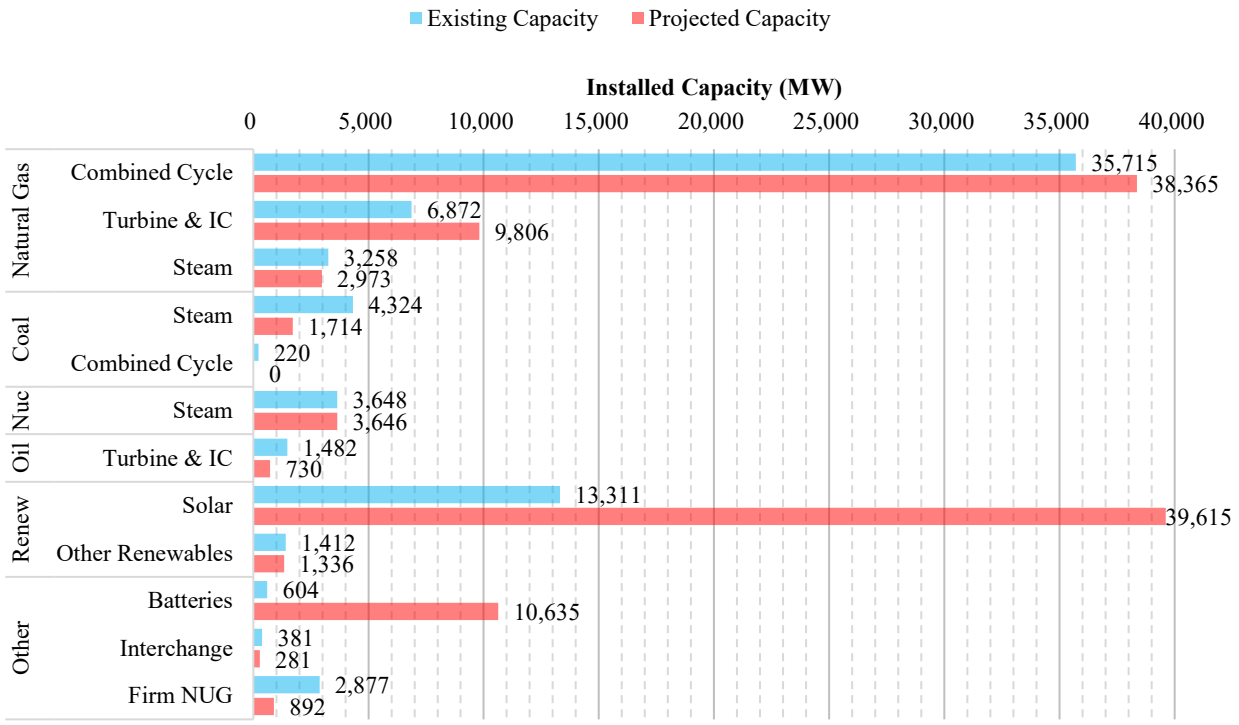
New Generation Planned

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity is expected to increase, making the addition of traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.

In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

Figure 20 illustrates the present and future aggregate capacity mix. The capacity values in Figure 20 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2025 TYSPs and the FRCC's 2025 Regional Load and Resource Plan.

Figure 20: State of Florida - Current and Projected Installed Capacity



Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Commission's Authority Over Siting

Any proposed steam or solar generating unit greater than 75 MW requires a certification under the Florida Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has exclusive jurisdiction to determine the need for new electric power plants through Section 403.519, F.S. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. When all parties stipulate that there are no disputed issues of material fact or law involved, the applicant may request that the Secretary of the Florida Department of Environmental Protection approve or deny certification, pursuant to Sections 403.508(6)(a) and 403.509(1)(a), F.S. Otherwise, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of a proposed line when there is a disputed issue of material fact or law, pursuant to Section 403.509(1)(b), F.S. There are only two planned units, both natural gas-fired combined cycles, requiring certification under the PPSA: a 576 MW unit with an in-service date of 2030 for JEA, and a 559 MW unit with an in-service date of 2032 for SEC. Based on these in-service dates, petitions are anticipated in 2026 and 2028 for JEA and SEC, respectively.

New Power Plants by Fuel Type

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. In April 2018, FPL received Combined Operating Licenses from the Nuclear Regulatory Commission for two future nuclear units, Turkey Point Units 6 and 7. These units are planned to be sited at FPL's Turkey Point site, the location of two existing nuclear generating units. The earliest possible in service date for these two units are outside the scope of the TYSP.

Florida is proactively exploring Small Modular Reactors (SMRs) to meet rising energy demands, though no units are currently operating. The state's efforts include a March 2025 feasibility report from the Commission and a related lawsuit filed by the Florida Attorney General against the U.S. Nuclear Regulatory Commission in April 2025. Major utilities like FPL and DEF are also considering SMR technology for their long-term power generation plans. In addition, the March 2025 feasibility report looked into military installations in partnership with a public utility.

Natural Gas

Several new natural gas-fired combustion turbines, internal combustion units, and combined cycle units are planned over the next 10 years. While combined cycle systems are the dominant generating unit type, combustion turbines that run only in simple cycle mode and internal combustion units (also called reciprocating engines), taken together, represent the third most abundant type of generating capacity, behind installed solar generation as well. As combustion turbines and internal combustion units are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the PPSA. Table 10 summarizes the approximately 4,233 MW of additional capacity from new natural gas-fired generating units proposed by the 2025 TYSP Utilities.

Table 10: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
PPSA Approved Units					
2026	SEC	Shady Hills Energy Center Unit 1	CC	546	Docket No. 20170267-EI
			Subtotal	**546**	
New Units Requiring PPSA Approval					
2030	JEA	Advanced Class 1x1 CC	CC	576	
2032	SEC	Unnamed CC	CC	559	
			Subtotal	**1,135**	
New Units Not Requiring PPSA Approval					
2025	TECO	South Tampa Resiliency Project	IC	75	4 Units
2025	LAK	Mcintosh Units MREP 1-3	IC	60	3 Units
2028	SEC	Unnamed CT 1	CT	393	
2030	SEC	Unnamed CT 2	CT	393	
2031	TECO	Future CT 1	CT	222	
2032	FPL	2x0 Manatee CT	CT	469	2 Units
2033	DEF	Undesignated CT 1 & 2	CT	491	2 Units
2034	DEF	Undesignated CT 3 & 4	CT	449	2 Units
			Subtotal	**2,552**	
			Total	**4,233**	

Source: 2025 TYSPs

In addition to the new generation listed in Table 10, multiple utilities are either acquiring existing natural gas-fired merchant generation facilities or are upgrading transmission to allow full capacity benefits from previously purchased resources. These include DEF's Osprey Energy Center (371 MW), FMPA's Orange facility (104 MW), and OUC's Osceola Generation Station (471 MW).

Transmission

As generation capacity increases, the transmission system must grow accordingly to maintain the capability of delivering energy to end-users. The Commission has been given broad authority pursuant to Chapter 366, F.S., to require reliability within Florida's coordinated electric grid and to ensure the planning, development, and maintenance of adequate generation, transmission, and distribution facilities within the state.

The Commission has authority over certain proposed transmission lines under the Florida Electric Transmission Line Siting Act (TLSA), contained in Sections 403.52 through 403.5365, F.S. To require certification under TLSA, a proposed transmission line must meet the following criteria: a nominal voltage rating of at least 230 kV, crossing a county line, and a length of at least 15 miles. Proposed lines in an existing corridor are also exempt from TLSA requirements, pursuant to Section 403.537, F.S. The Commission is the sole forum for determinations of the reliability need and the proposed starting and end points for lines requiring TLSA certification. The proposed corridor route is subsequently determined by the Florida Department of Environmental Protection during the certification process. Much like with the PPSA, when all parties stipulate that there are no disputed issues of material fact or law involved, the applicant may request that the Secretary of the Florida Department of Environmental Protection approve or deny certification, pursuant to Sections 403.527(6)(a) and 403.529(1)(a), F.S. Otherwise, the Governor and Cabinet sitting as the

Siting Board ultimately must approve or deny the overall certification of a proposed line when there is a disputed issue of material fact or law, pursuant to Section 403.529(1)(b), F.S.

The Commission is also monitoring new technologies and trends associated with transmission. The use of advanced conductors that are being designed to operate at higher temperatures with less sag compared to traditional conductors allows for higher current flow and increased transmission line capacity within existing rights-of-way. Using new sensors and control systems with real-time data allows the potential for dynamic line rating systems to assess and adjust the carrying capacity of transmission lines based on loading and weather conditions. Advanced power flow controllers that enable active control and optimization of power flow across the transmission network, potentially reduce congestion, improve system stability, and enhance the integration of renewable energy sources.

Table 11 lists all proposed transmission lines in the 2025 TYSPs and the FRCC 2025 Regional Load and Resource Plan that require TLSA certification. The only planned lines have already received the approval of the Commission.

Table 11: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Sweatt to Whidden	79	230	05/2022	09/2022	06/2026
DEF	DeLand West – Dona Vista	26.5	230	07/2025	TBD	01/2030

Source: 2025 TYSPs and FRCC 202 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is an investor-owned, and Florida's largest, electric utility. FPL's service territory previously was solely in the FRCC Region and consisted of South Florida and the east coast. FPL's parent company, NextEra Energy Inc., acquired Gulf Power Company (GPC) in January 2019. Resource planning is now being done for the single entity of FPL, with the former GPC territory referred to as FPL's Northwest Florida Division (FPL NWFL). As an investor-owned utility, FPL is subject to the regulatory authority of the Commission over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds the FPL 2025 TYSP suitable for planning purposes.

Load and Energy Forecasts

In 2024, FPL's service area had approximately 5,959,750 customers and annual retail energy sales of 129,386 GWh, accounting for approximately 52.6 percent of Florida's annual retail energy sales. The total number of customers and total retail energy sales grew by approximately 2.0 percent and 1.2 percent, respectively, in 2024.

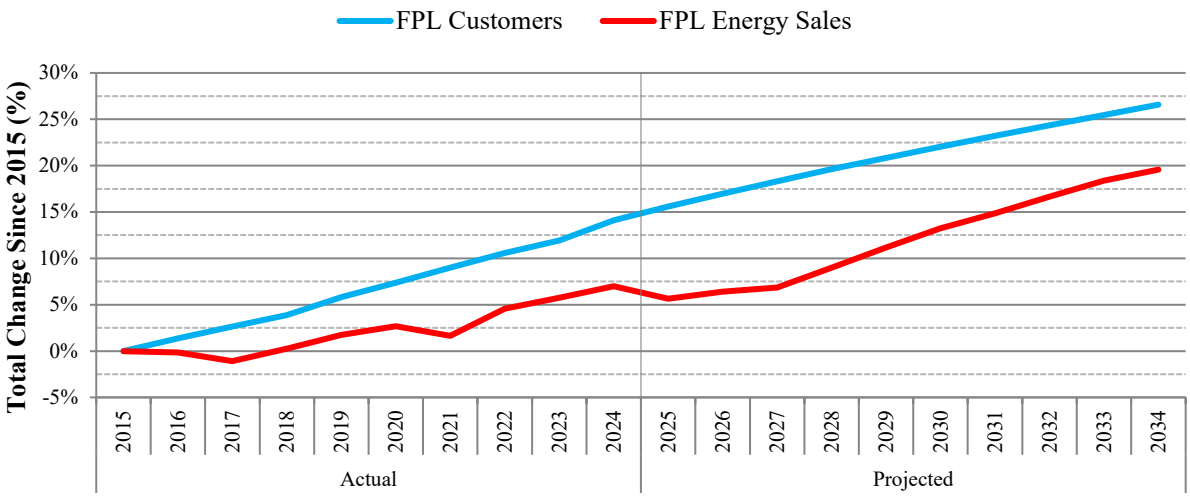
Over the past 10 years, FPL's customer base has increased by 14.1 percent, while retail energy sales have grown by approximately 7.0 percent. For the 2025 TYSP forecast horizon, customers for the FPL system are forecasted to grow by 1.0 percent per year, with the residential and commercial classes accounting for the majority of the increase. According to the Utility, growth is closely linked to Florida's expanding population, housing market, and business activity, all of which are projected to remain positive.

FPL's historical underlying trends affecting average energy UPC across all customer classes include weather variability, economic conditions, and changes in customer behavior or operations. The residential UPC has ranged from relatively flat to slightly increasing in recent years. The change in residential consumption is attributable to the relative increased usage of electronics and equipment within residences, which is offset, in part, by continued improvements in energy efficiency, such as higher efficiency building codes, appliances, lighting, and HVAC systems. The trend in commercial UPC has been relatively flat over the past couple of years. Industrial UPC appeared relatively flat to slow but had a steady decline in the most recent years. The historical decline may be linked to shifts in the local industrial base, customer migration, increased energy efficiency, or operational changes among key industrial customers.

In the forecast period, residential UPC is forecasted to decline gradually over time, primarily driven by continued improvements in energy efficiency, such as higher efficiency building codes, appliances, lighting, and HVAC systems. In addition, increasing customer adoption of energy-saving behaviors and technologies (e.g., smart thermostats, solar panels) is expected to further reduce UPC. The commercial UPC is also expected to be generally flat to slightly declining for similar reasons. Energy efficiency standards, advanced building systems, and retrofits are expected to reduce consumption on a per-customer basis though some commercial customers may see stable or even increasing UPC due to higher operational loads and continued expansion. Industrial UPC is forecasted to increase modestly overall, driven by the expected addition of usage by large load customers.

Over the current TYSP forecast horizon, FPL's total energy sales to ultimate customers are forecasted to increase steadily, driven primarily by customer growth. Florida's strong population growth, housing development, and economic expansion continue to be the main drivers of rising energy demand across the state. Figure 21 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FPL filed in its 2025 TYSP.

Figure 21: FPL Growth



Source: 2025 TYSP

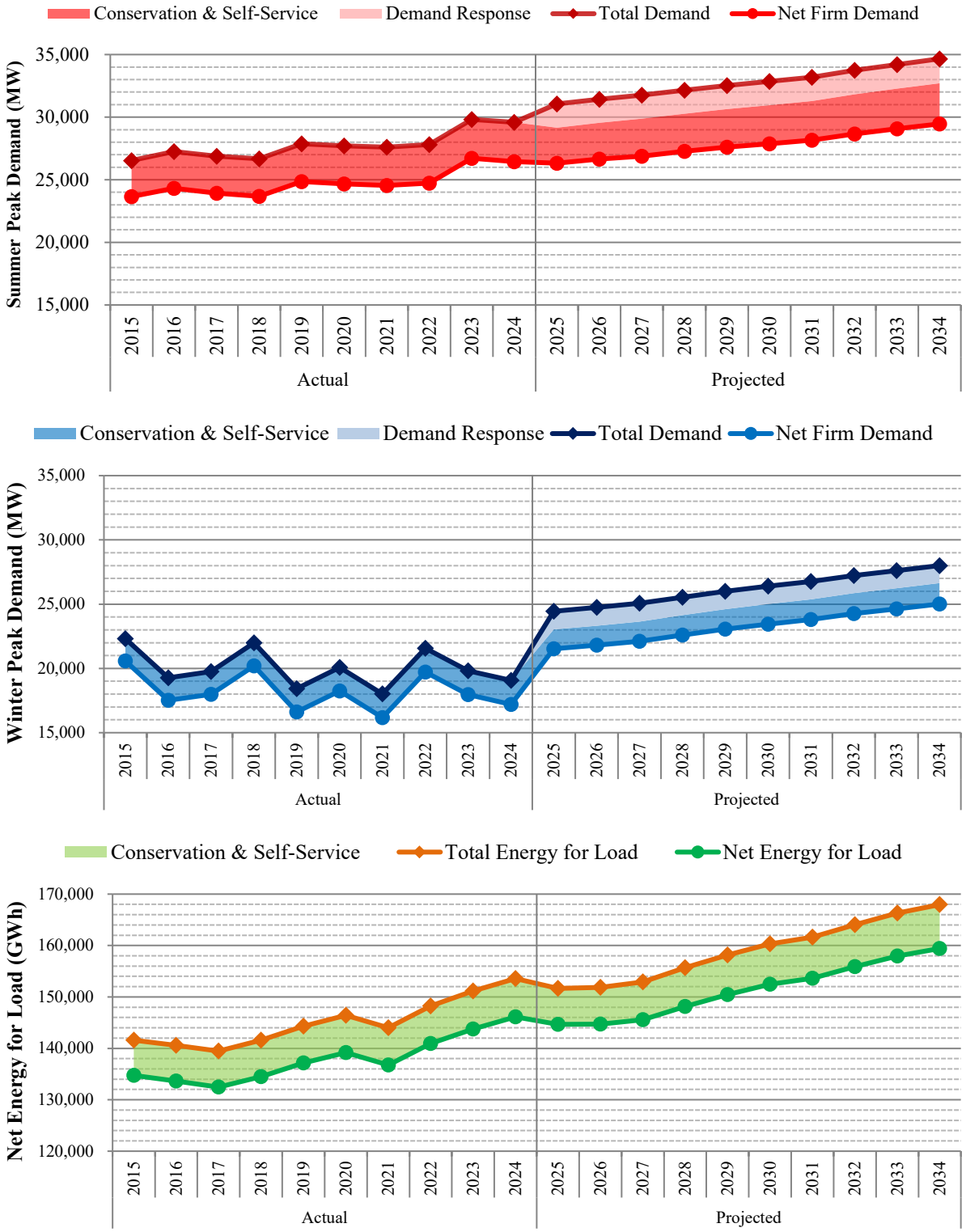
As stated earlier, on January 1, 2019, GPC became a subsidiary of NextEra Energy, Inc., FPL's parent company, and the systems were integrated into a single electric system, effective January 1, 2022. The three graphs in Figure 22 show FPL and GPC's combined seasonal peak demand, summer and winter, and net energy for load, for the historic years 2015 through 2021, and integrated FPL/GPC historical data for 2022 through 2024, and forecast data 2025 through 2034.

As an investor-owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Commission reviewed and established energy conservation goals for FPL and approved FPL's 2025-2034 DSM Plan with modifications.[10,11] In preparing its 2025 TYSP seasonal peak demand and energy forecasts, FPL reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 22. These graphs include the impact of DSM, and for future years assume that all available demand response resources will be activated during the seasonal peak. During the past 10 years, demand response has not been activated during seasonal peak demand.

[10] Order No. PSC-2024-0505-FOF-EG, issued on December 18, 2024, in Docket No. 20240012-EI, *In re: Commission review of numeric conservation goals (Florida Power & Light Company)*

[11] Order No. PSC-2025-0292-PAA-EG, issued on July 29, 2025, in Docket No. 20250048-EG, *In re: Petition for approval of proposed DSM plan, by Florida Power & Light Company*.

Figure 22: FPL Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2024 and the projected fuel mix for 2034. FPL relies primarily upon natural gas for energy generation, making up 71 percent of net energy for load in 2024. FPL is projected to use natural gas for less than half of its energy generation by 2033. Only three utilities, FPL, GRU, and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2034, natural gas will remain FPL's primary fuel source at approximately 46 percent, while renewables will account for 35 percent, followed by nuclear at 18 percent.

Table 12: FPL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	104,335	71.4%	73,448	45.8%
Coal	533	0.4%	738	0.5%
Nuclear	28,009	19.2%	29,136	18.2%
Oil	116	0.1%	1	0.0%
Renewable	13,449	9.2%	56,831	35.4%
Interchange	0	0.0%	0	0.0%
NUG & Other	(340)	(0.2%)	319	0.2%
Total	**146,102**		**160,473**	

Source: 2025 TYSP

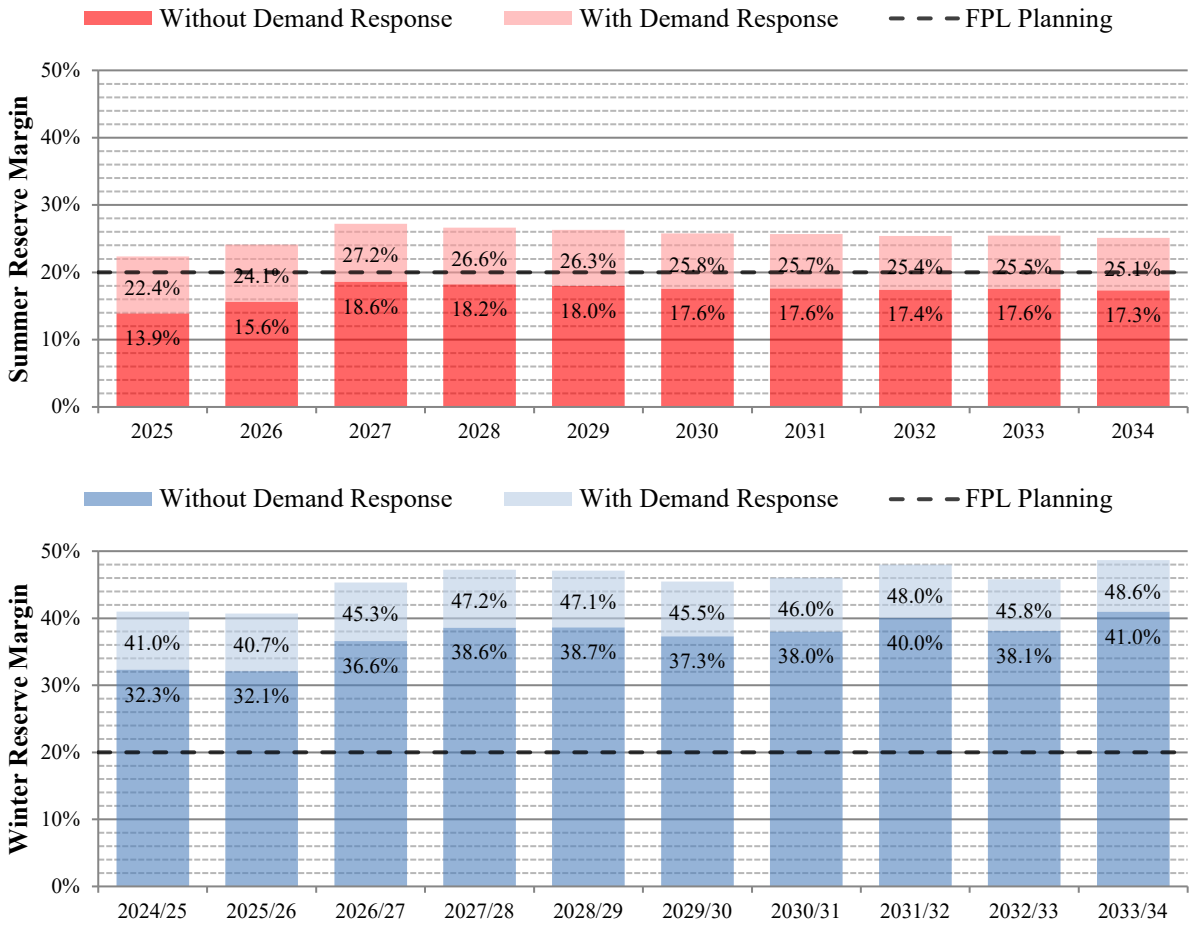
Reliability Requirements

Traditionally, FPL has used three methods for its reliability review. The three methods are a planning reserve margin, a generation-only planning reserve margin, and a LOLP. Since 1999, FPL has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[12] FPL also elects to maintain a generation-only planning reserve margin of 10 percent. The Commission has yet to approve the 10 percent generation-only planning criteria, and it has not been the controlling factor for any unit additions. Figure 23 displays the forecast planning reserve margin with and without the use of demand response. As shown, in the future FPL's generation needs are controlled by its summer peak.

For its reserve margin planning, FPL has considered only a portion of its solar facilities to be firm for seasonal peak planning purposes, primarily for summer. Of its 6,993 MW of existing utility-owned solar generation, it treats it as contributing 3,194 MW or 45.7 percent in summer, and 92 MW or 1.3 percent in winter. Planned solar generation additions of 17,508 MW are only considered firm for an additional 1,201 MW or 6.9 percent in summer, and 85 MW or 0.5 percent in winter. Therefore, existing utility-owned solar contributes 12.1 percent of its planned summer reserve margin in 2025, with new solar generation increasing the contribution to 14.9 percent in 2034.

[12] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 23: FPL Reserve Margin Forecast



Source: 2025 TYSP

In addition to reserve margin, FPL uses LOLP, which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. FPL uses a maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement has historically been the controlling factor for the addition of capacity.

In its 2025 TYSP, FPL is shifting from its prior usage of a probabilistic model that evaluated daily peaks for the year to determine its LOLP value, to a new stochastic model to simulate various weather and unit outages, producing several hundred scenarios. FPL's 2025 TYSP only contained a summary of this methodology and did not provide a majority of the inputs or results. Using this analysis, FPL projected significant resource shortfalls primarily in off-peak periods, and is the controlling factor in generation additions. The use of this new methodology is at issue in FPL's current rate case before the Commission in Docket No. 20250011-EI, and any future Commission decision(s) associated with it will be addressed in FPL's next TYSP filing.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period as are described in Table 13. Over the planning period, FPL will retire its remaining coal unit, Scherer Unit 3, which it acquired from its purchase of GPC. This and other retirements are partially offset by planned upgrades of its existing natural gas combined cycle generating units over the planning period, which increases summer capacity by 80 MW.

FPL plans a single new fossil fuel generating addition over the 10-year period, a pair of natural gas-fired combustion turbines in 2032 with a combined capacity of 469 MW. All other generation additions consist of solar and battery facilities, some of which may be constructed in a combined manner. Overall, FPL is planning a total of 17,508 MW and 7,605 MW of solar and battery storage capacity, respectively. For planning purposes, these are only considered to contribute towards summer firm peak a portion of their capacity, or 1,201 MW and 3,585 MW for solar and battery storage, respectively. None of these additions requires a need determination pursuant to the PPSA.

Table 13: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2026	Pea Ridge 1-3	GT NG	12		3 Units Total
2028	Lansing Smith 3A	CT LO	32		
2029	Gulf Clean Energy Center 4 & 5	ST NG	150		2 Units Total
2030	Perdido 1 & 2	IC LFG	3		2 Units Total
2034	Scherer 3	BIT ST	215		
		Total Retirements	**412**	**-**	
New Units					
2025	Gulf Battery Storage	BS	522	349	
2026	Sited Solar Plants	PV SUN	894	113	12 Sites
2026	Unsited Energy Storage	BS	1,420	997	
2027	Sited Solar Plants	PV SUN	1,192	64	16 Sites
2027	Unsited Energy Storage	BS	820	432	
2028	Unsited Solar Plants	PV SUN	1,490	79	20 Sites
2028	Unsited Energy Storage	BS	596	298	
2029	Unsited Solar Plants	PV SUN	1,788	95	24 Sites
2029	Unsited Energy Storage	BS	596	247	
2030	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2030	Unsited Energy Storage	BS	596	244	
2031	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2031	Unsited Energy Storage	BS	596	244	
2032	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2032	2x0 Manatee CT	CT NG	469		2 Units
2033	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2033	Unsited Energy Storage	BS	1,192	424	
2034	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2034	Unsited Energy Storage	BS	1,267	350	
		Total New Units	**24,613**	**4,531**	
		Net Additions	**24,207**		

Source: 2025 TYSP

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Utility's service territory is within the FRCC region and is primarily located in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, DEF had approximately 2,009,470 customers and annual retail energy sales of 41,132 GWh, accounting for approximately 16.7 percent of Florida's annual retail energy sales. DEF's total customers and total retail energy sales respectively grew approximately 2.1 percent and 0.7 percent in 2024. Over the last 10 years, DEF's customer base has increased by 16.7 percent, while retail energy sales have grown by 6.7 percent.

Historically, DEF's customer growth has always been dominated by the residential and commercial customer classes. Customer growth trends are driven by broad economic and demographic factors such as population growth, migration, retirement, housing, mortgage rates, and job growth. More recent information reflects a return to the long-term trend of population migration into Florida. Commercial customer growth typically tracks residential growth supplying needed services.

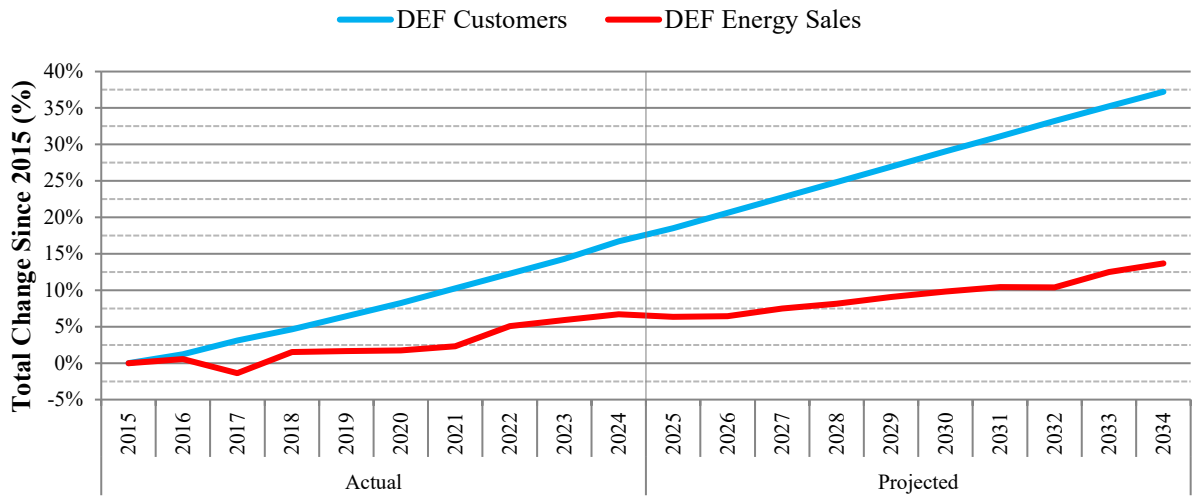
DEF reported that, from 2015 to 2024, its respective residential and commercial UPC annual growth rates decreased by approximately of 0.7 percent and 0.8 percent. These declines are primarily driven by fluctuations in price of electricity, end-use appliance saturation and efficiency improvement, more stringent building codes, housing type/size, and energy source of the air conditioning equipment. In addition, the Utility is aware that more recently, the customer's ability to self-generate has begun to make an impact on average usage. A small percentage of industrial/commercial customers have chosen to install their own natural gas generators, reducing energy consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind the meter. DEF also noted that the penetration of plug-in EVs has grown, yielding an increase in residential UPC; however, the impact of rooftop solar generation on UPC continues to exceed the impact of EVs. In contrast, for the same historical period of 2015 to 2024, DEF's industrial UPC increased at an annual growth rate of 3.3 percent due to flat load combined with declining customer counts.

For 2025 to 2034, DEF is expecting its respective residential and commercial UPC to decrease by 1.0 percent and 0.4 percent per year. According to the Utility, the disparity between the going forward rates of residential and commercial UPC is the result of the anticipated growing residential behind the meter solar adoption. DEF is also expecting its industrial UPC to increase 0.7 percent annually, reflecting relatively flat sales and customer growth.

For the 2025 TYSP forecast horizon, DEF's customer base is projected to grow at an average annual rate of 1.6 percent approximately, and its retail energy sales amount is projected to grow at an average annual rate of 0.7 percent approximately.

Figure 24 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan DEF filed in its 2025 TYSP.

Figure 24: DEF Growth



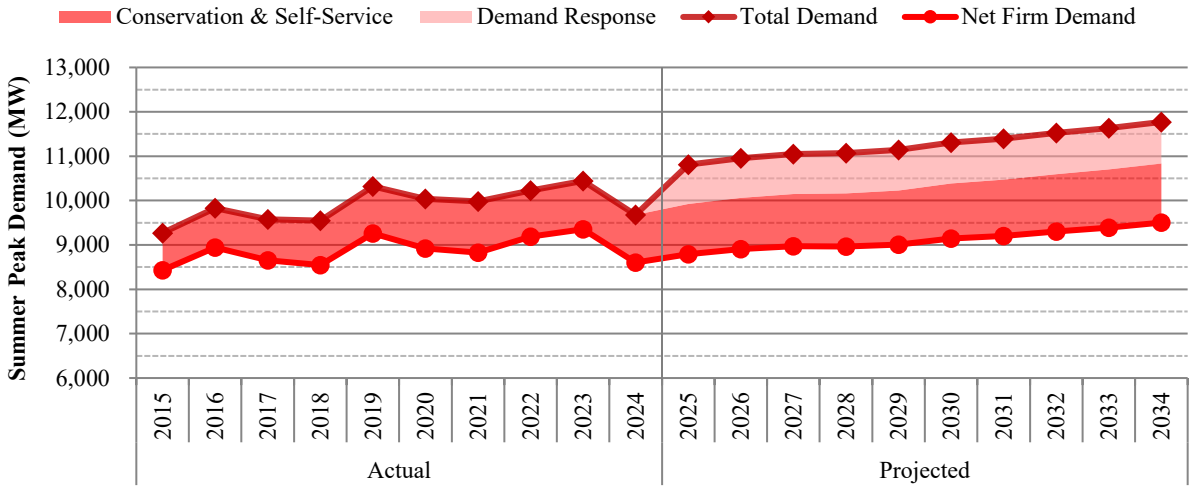
Source: 2025 TYSP

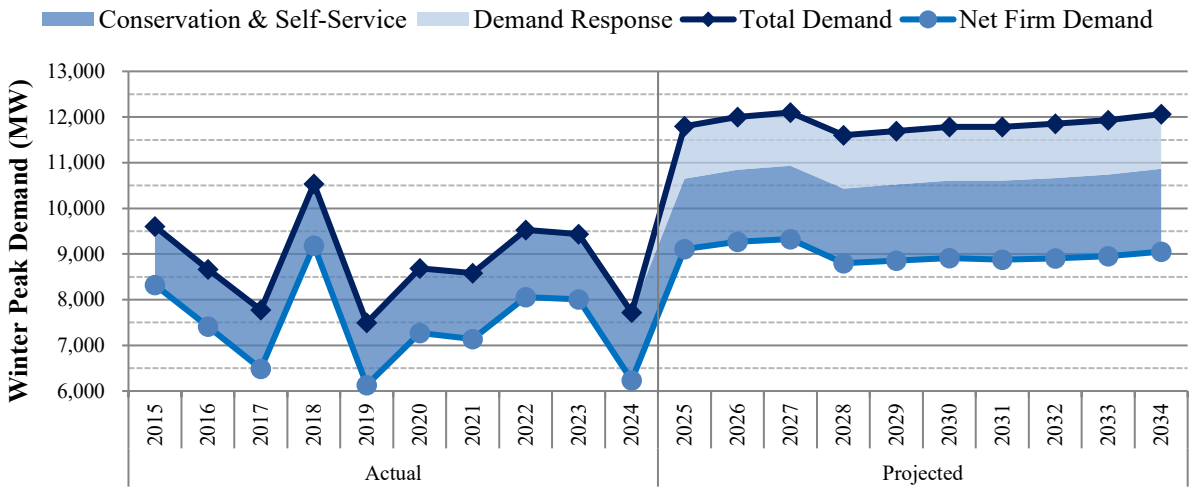
The three graphs in Figure 25 show DEF's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the full impact of DSM and assume that all available demand response resources will be activated during the seasonal peak. During the past 10 years, demand response has not been activated during seasonal peak demand. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Commission reviewed and established energy conservation goals for DEF and approved DEF's 2025-2034 DSM Plan.[13,14] In preparing its 2025 TYSP seasonal peak demand and energy forecasts, DEF reflects these Commission-approved FEECA goals through the forecast horizon (through 2034), as shown in Figure 25.

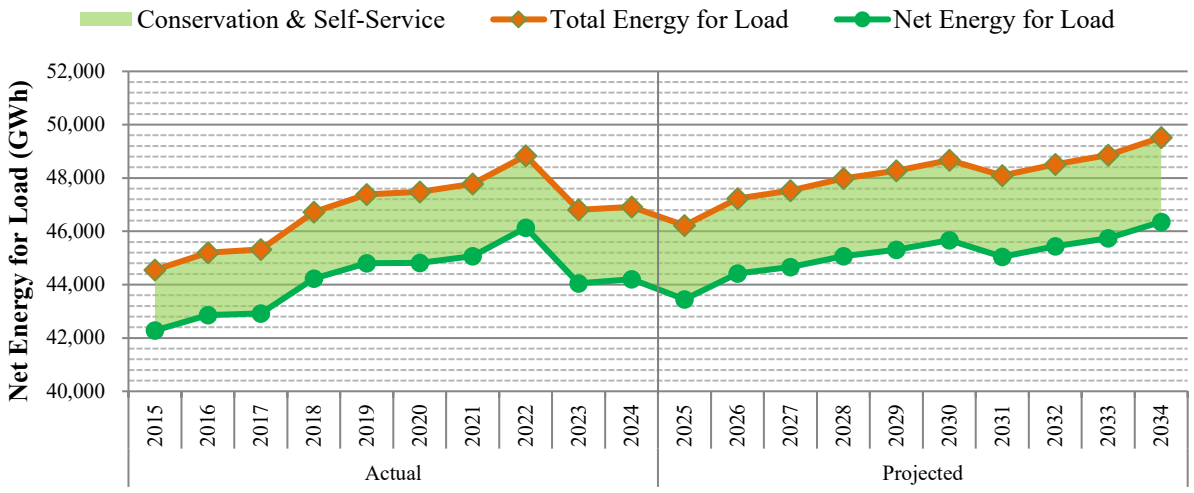
[13] Order No. PSC-2024-0429-FOF-EG, issued September 20, 2024, in Docket No. 20240013-EI, *In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC)*.

[14] Order No. PSC-2025-0088-PAA-EG, issued March 24, 2025, in Docket No. 20240169-EG, *In re: Petition for approval of proposed demand-side management plan and demand-side management program standards, by Duke Energy Florida, LLC*.

Figure 25: DEF Demand and Energy Forecasts







Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. DEF relies primarily upon natural gas for energy generation, making up approximately 85 percent of net energy for load in 2024. DEF plans to increase renewable energy generation over the planning period, offsetting both natural gas and coal usage. DEF projects that renewable energy will provide 29 percent of its generation by 2034, which is the fourth highest percentage of renewable energy generation in 2034 of the TYSP Utilities. Natural gas would remain the primary fuel, at 70 percent in 2034.

Table 14: DEF Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	37,494	84.8%	32,440	70.0%
Coal	3,262	7.4%	657	1.4%
Nuclear	0	0.0%	0	0.0%
Oil	30	0.1%	3	0.0%
Renewable	3,354	7.6%	13,250	28.6%
Interchange	(541)	(1.2%)	9	0.0%
NUG & Other	601	1.4%	0	0.0%
Total	**44,200**		**46,359**	

Source: 2025 TYSP and Data Responses

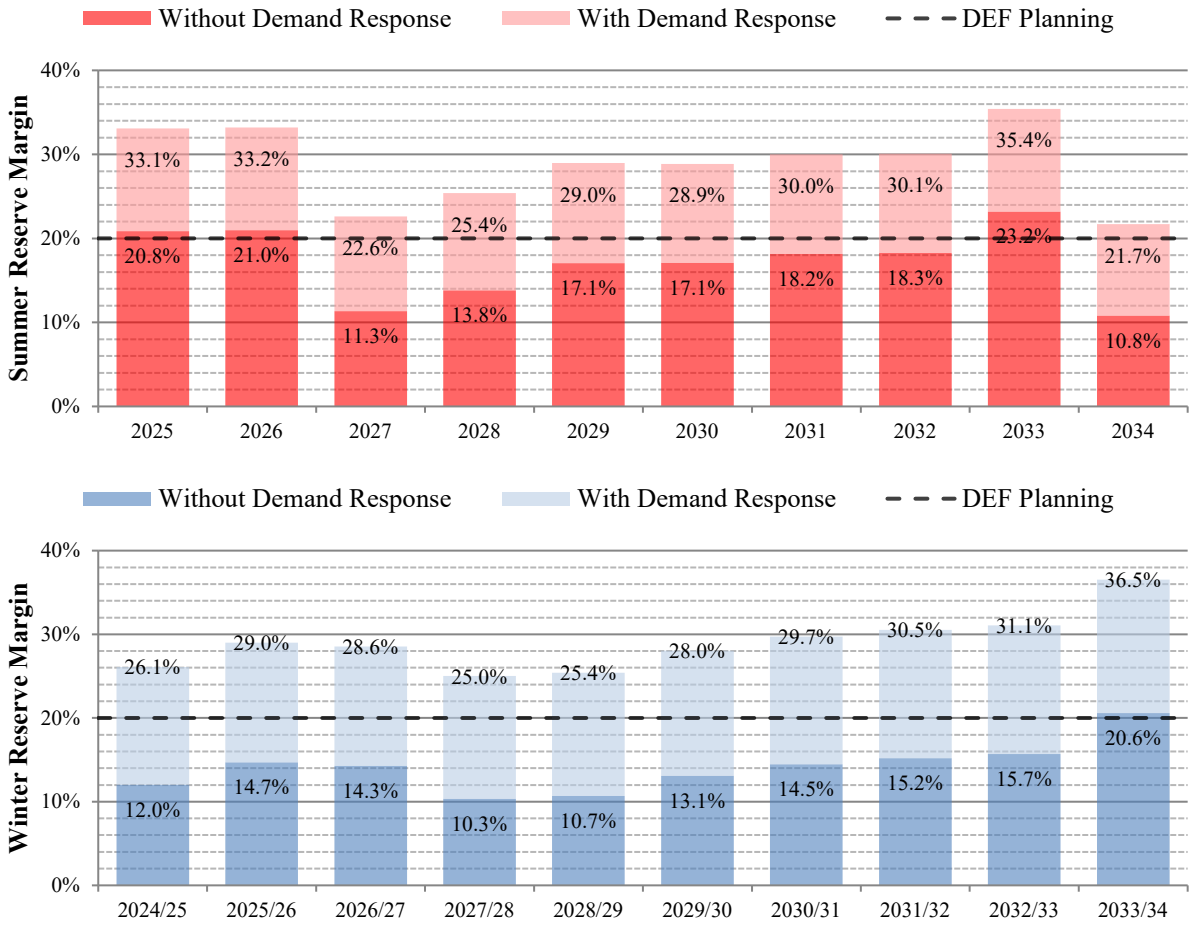
Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[15] Figure 26 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are mostly controlled by its summer peaking throughout the planning period.

As part of its evaluation of its system reliability, DEF also conducted an evaluation of the contribution of its existing and planned solar generation assets towards its seasonal peaks. The methodology selected by DEF, Effective Load Carrying Capacity (ELCC), determined that DEF's existing solar capacity has a reduced benefit for summer peaks than previously calculated, from 54.7 percent to 53.7 percent and that the facilities also contribute approximately 5 percent to the winter peak. The ELCC methodology also provides that as additional resources are added to the system, the net contribution will decrease, similar to observed trends in prior planning methodologies. DEF plans to perform future ELCC studies to account for new solar and battery additions. The Commission will have an opportunity to review this methodology during a future proceeding.

[15] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 26: DEF Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 15. Over the planning period, DEF will retire its only remaining coal-fired units, Crystal River Units 4 and 5, in addition to several simple cycle combustion turbines fueled by oil or natural gas. This is partially offset by planned upgrades to its existing natural gas combined cycle generating units, which increase summer capacity by 256 MW, and improved transmission facilities that will allow DEF to fully utilize the acquired Osprey plant, which increases its firm contribution to 371 MW. DEF also plans on several solar QF purchases, totaling an additional 225 MW.

DEF identified two new fossil fuel generating addition over the 10-year period, each a pair of natural gas-fired combustion turbines, with combined capacities of 491 MW in 2033 and 449 MW in 2034. All other generation additions consist of solar and battery facilities, with a majority of the storage facilities constructed in combination with the solar additions. Overall, DEF is planning a total of 4,463 MW and 1,330 MW of solar and battery storage capacity, respectively. For planning purposes, these are only considered to contribute towards summer firm peak a portion of their capacity, or 873 MW and 1,088 MW for solar and battery storage, respectively. None of these additions requires a need determination pursuant to the PPSA.

Table 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2026	Bayboro Units P1-P4	CT DFO	137		4 Units
2027	Debary Units P2-P6	CT DFO	227		5 Units
2027	Bartow Units P1 & P3	CT DFO	82		2 Units
2034	Intercession City P1-P6	CT DFO	275		6 Units
2034	Bartow P2, P4	CT NG	86		2 Units
2034	Suwannee P1-P3	CT NG	145		3 Units
2034	Crystal River 4 & 5	ST BIT	1,422		2 Units
	Total Retirements		**2,374**	**0**	
New Units					
2025	Sundance Solar Plant	PV SUN	75	26	
2026	Sited Solar Plants	PV SUN	524	186	7 Sites
2027	Unsited Solar Plants	PV SUN	300	100	4 Sites
2027	Powerline Energy Storage	BAT	100	90	
2028	Unsited Solar Plants	PV SUN	225	62	3 Sites
2028	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2028	Unsited Solar Plus Storage	BAT	100	90	
2029	Unsited Solar Plant	PV SUN	225	62	3 Sites
2029	Unsited Battery Storage	BAT	225	203	
2029	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2029	Unsited Solar Plus Storage	BAT	100	90	
2030	Unsited Solar Plants	PV SUN	225	48	3 Sites
2030	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2030	Unsited Solar Plus Storage	BAT	100	90	
2031	Unsited Solar Plants	PV SUN	449	74	6 Sites
2031	Unsited Solar Plus Storage	PV SUN	150	23	2 Sites
2031	Unsited Solar Plus Storage	BAT	100	90	
2032	Unsited Solar Plants	PV SUN	449	48	6 Sites
2032	Unsited Solar Plus Storage	PV SUN	150	14	2 Units
2032	Unsited Solar Plus Storage	BAT	100	85	
2033	Unsited Solar Plants	PV SUN	449	43	6 Sites
2033	Undesignated CT P1 & P2	CT NG	491		2 Units
2033	Unsited Solar Plus Storage	PV SUN	150	14	2 Sites
2033	Unsited Solar Plus Storage	BAT	100	70	
2034	Undesignated CT P3 & P4	CT NG	449		2 Units
2034	Unsited Battery Storage	BAT	300	210	
2034	Unsited Solar Plus Storage	PV SUN	150	14	2 Units
2034	Unsited Solar Plus Storage	BAT	100	70	
	Total New Units		**6,236**	**1,898**	
	Net Additions		**3,862**		

Source: 2025 TYSP

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, TECO had approximately 849,877 customers and annual retail energy sales of 20,702 GWh, accounting for approximately 8.4 percent of Florida's annual retail energy sales. Over the last 10 years, TECO's customer base has increased by approximately 18.3 percent, while retail energy sales have increased by approximately 9.0 percent.

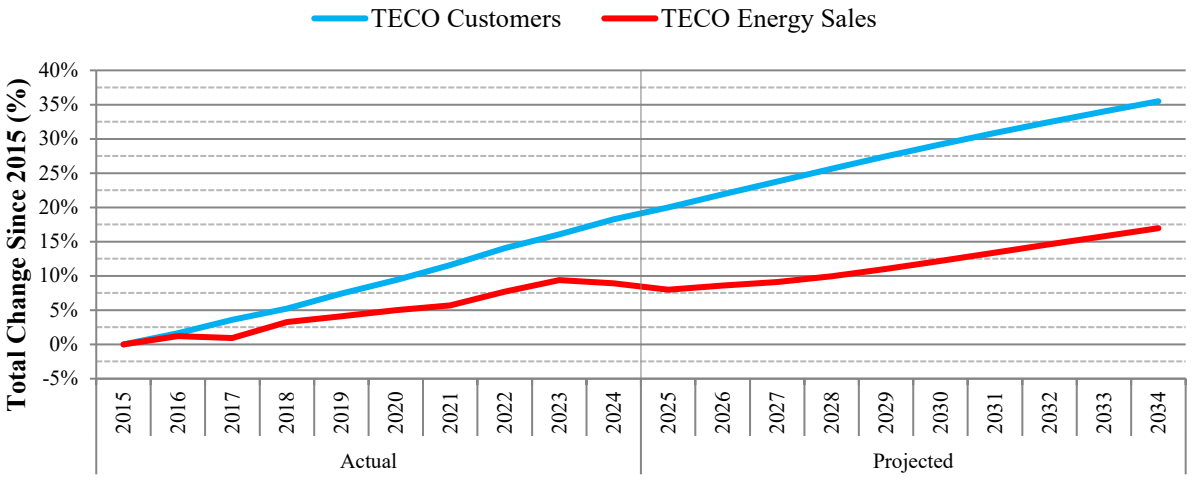
TECO's total customer growth in 2024 averaged 1.9 percent approximately with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.4 percent annually.

TECO's residential UPC and commercial UPC growth rates were both slightly lower in 2024 than in 2023, primarily due to the record-breaking heat in 2023. TECO's industrial UPC declined by 1.4 percent in 2024 and is expected to be flat for 2025. Over the forecast horizon, TECO's residential UPC is expected to decline at an average annual rate of 0.3 percent over the TYSP's forecast horizon. The primary drivers behind the decline in per-customer usage are increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and housing mix. TECO's commercial and industrial UPC is projected to decrease slightly, at an annual rate of 0.1 percent and 0.2 percent, respectively.

In 2024, TECO's retail energy sales were 0.4 percent lower than in 2023. For the next 10 years, the Utility's retail energy sales are projected to grow at an annual average rate of approximately 0.9 percent. This is below the projected customer growth rate of 1.4 percent primarily due to continued declines in UPC, as well as declines in the phosphate sector as the mining industry continues to move south and out of TECO's service territory.

Figure 27 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that TECO filed in its 2025 TYSP.

Figure 27: TECO Growth



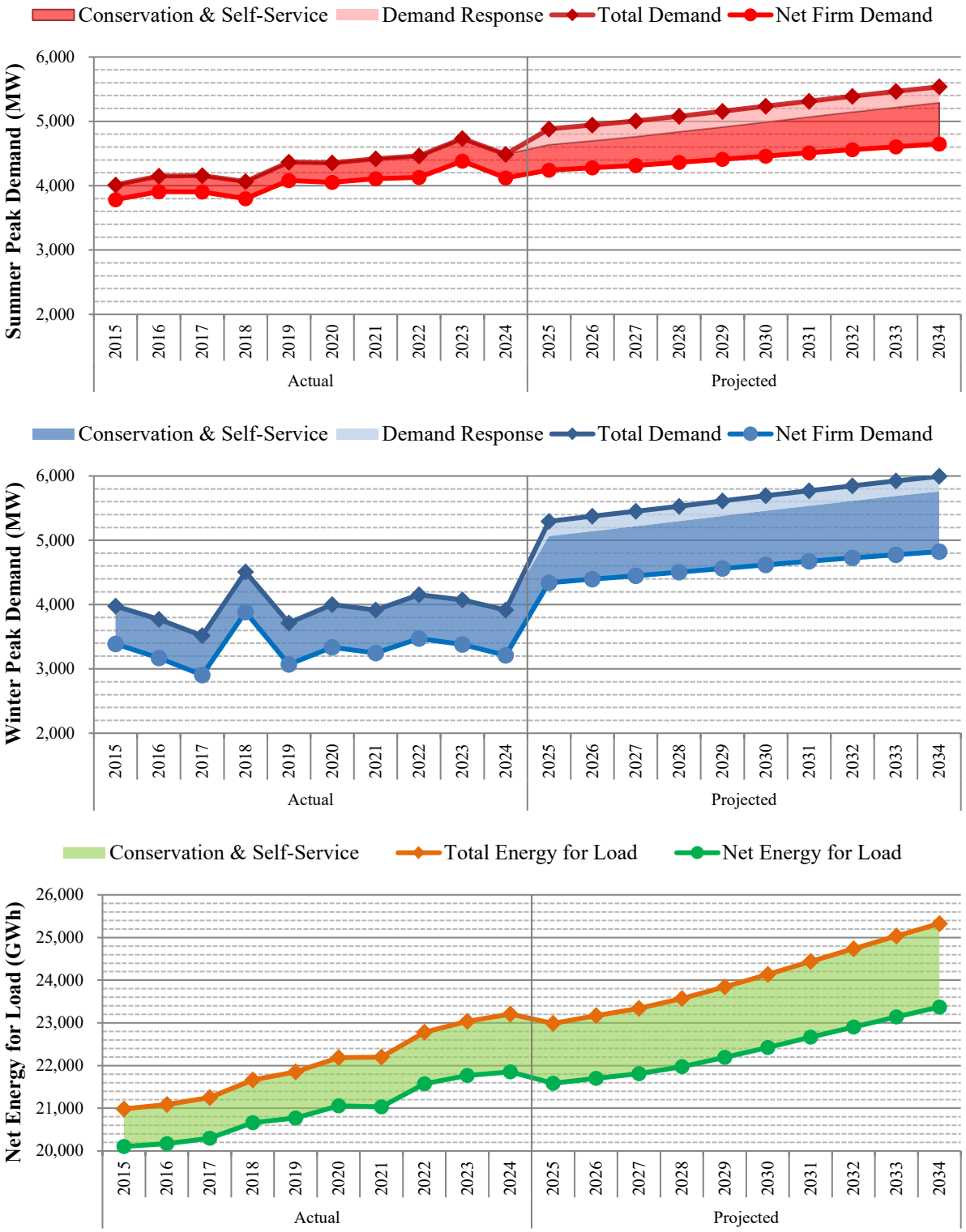
Source: 2025 TYSP

The three graphs in Figure 28 show TECO's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the full impact of DSM, and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding the summer of 2013 and winters of 2017-2018 and 2018-2019. As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Commission reviewed and established energy conservation goals for TECO and approved TECO's 2025-2034 DSM Plan.[16,17] In preparing its 2025 TYSP seasonal peak demand and energy forecasts, TECO reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 28.

[16] Order No. PSC-2024-0430-FOF-EG, issued September 20, 2024, in Docket No. 20240014-EI, *In re: Commission review of numeric conservation goals (Tampa Electric Company)*.

[17] Order No. PSC-2025-0093-PAA-EG, issued March 24, 2025, in Docket No. 20240163-EG, *In re: Petition for approval of proposed demand-side management plan and demand-side management program standards, by Tampa Electric Company*.

Figure 28: TECO Demand and Energy Forecasts



Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. Natural gas is used for the majority of TECO's energy generation, and accounts for approximately 82 percent of net energy for load in 2024 and is projected to account for approximately 72 percent in 2034. Renewables, primarily solar, are anticipated to increase from 10 percent in 2024 to 25 percent in 2034.

Table 16: TECO Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	17,999	82.4%	16,864	72.1%
Coal	58	0.3%	323	1.4%
Nuclear	0	0.0%	0	0.0%
Oil	4	0.0%	0	0.0%
Renewable	2,235	10.2%	5,870	25.1%
Interchange	33	0.2%	281	1.2%
Other	1,523	7.0%	36	0.2%
Total	**21,852**		**23,374**	

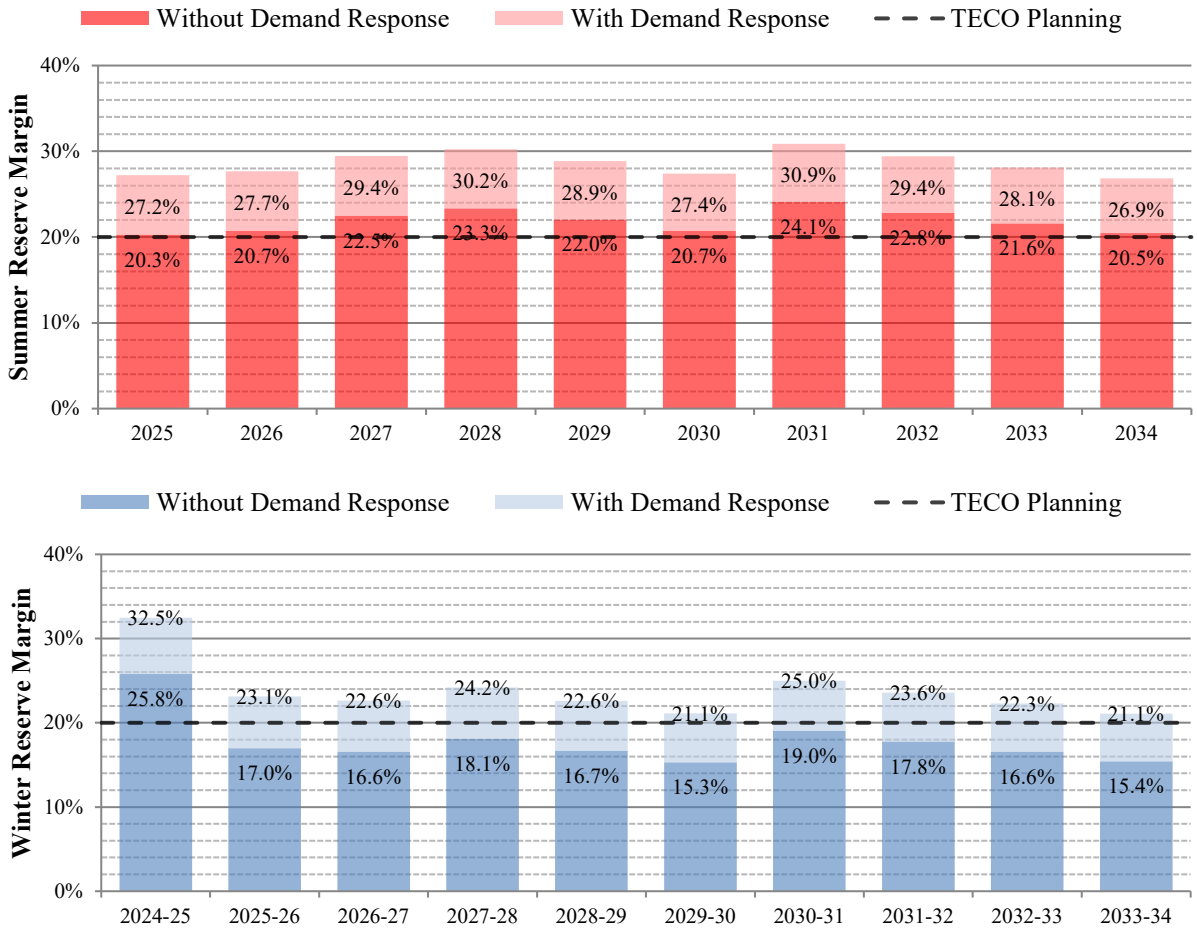
Source: 2025 TYSP and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[18] TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 29 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are being controlled by its winter peak. TECO's current and planned investments in solar generation contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions.

[18] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 29: TECO Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

TECO projects multiple unit additions during the planning period, as described in Table 15. While TECO does not plan to retire any generating units, it is converting Polk Unit 1 from a petcoke-fired combined cycle system to a natural gas-fired simple cycle combustion turbine, which reduces its output by approximately 30 MW. This is offset by planned upgrades to its existing natural gas combined cycle generating units, which increase summer capacity by 140 MW.

TECO plans two new fossil fuel generating additions over the 10-year period, all natural gas-fired, including a set of four reciprocating engines in 2025 with a capacity of 75 MW, and a simple cycle turbine in 2031 with a capacity of 222 MW. All other generation additions consist of solar and battery facilities. Overall, TECO is planning a total of 1,340 MW and 195 MW of solar and battery storage capacity, respectively. For planning purposes, the batteries are assumed to contribute their full capacity, while the solar facilities are only considered to contribute towards summer firm peak a portion of their capacity, 26 MW. None of these additions requires a need determination pursuant to the PPSA.

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
	None				
		Total Retirements	**0**	**0**	
New Units					
2025	South Tampa Resilience Project	IC NG	75		4 Units
2025	Sited Solar Plants	PV SUN	149	7	2 Sites
2025	Sited Energy Storage	BAT	100	100	3 Sites
2026	Sited Solar Plants	PV SUN	227	8	4 Sites
2027	Brewster Solar Plant	PV SUN	16	0	1 Site
2027	Unsited Solar Plant	PV SUN	149	2	2 Sites
2027	Unsited Energy Storage	BAT	95	95	2 Sites
2028	Unsited Solar Plants	PV SUN	204	3	3 Sites
2029	Unsited Solar Plants	PV SUN	149	2	2 Sites
2030	Unsited Solar Plants	PV SUN	149	2	2 Sites
2031	Future CT 1	CT NG	222		
2031	Unsited Solar Plant	PV SUN	75	1	1 Site
2032	Unsited Solar Plant	PV SUN	75	1	1 Site
2033	Unsited Solar Plant	PV SUN	75	1	1 Site
2034	Unsited Solar Plant	PV SUN	75	1	1 Site
		Total New Units	**1,835**	**223**	
		Net Additions	**1,835**	**223**	

Source: 2025 TYSP

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's seventh largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the Utility's TYSP. FMPA is responsible for planning activities associated with ARP member systems. For a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, FMPA had approximately 293,231 customers and annual retail energy sales of 6,254 GWh, accounting for approximately 2.5 percent of Florida's annual retail energy sales. Over the last 10 years, FMPA's customer base has increased by 17.6 percent, while energy sales have increased by 11.3 percent.

In 2024, FMPA's total customer growth averaged 2.5 percent approximately. It noticed strong customer count gains in certain areas of the ARP participant service territories where residential sector expansion is the primary driver of customer gains. Florida in-migration has continued to be the leading driver of ARP customer growth.

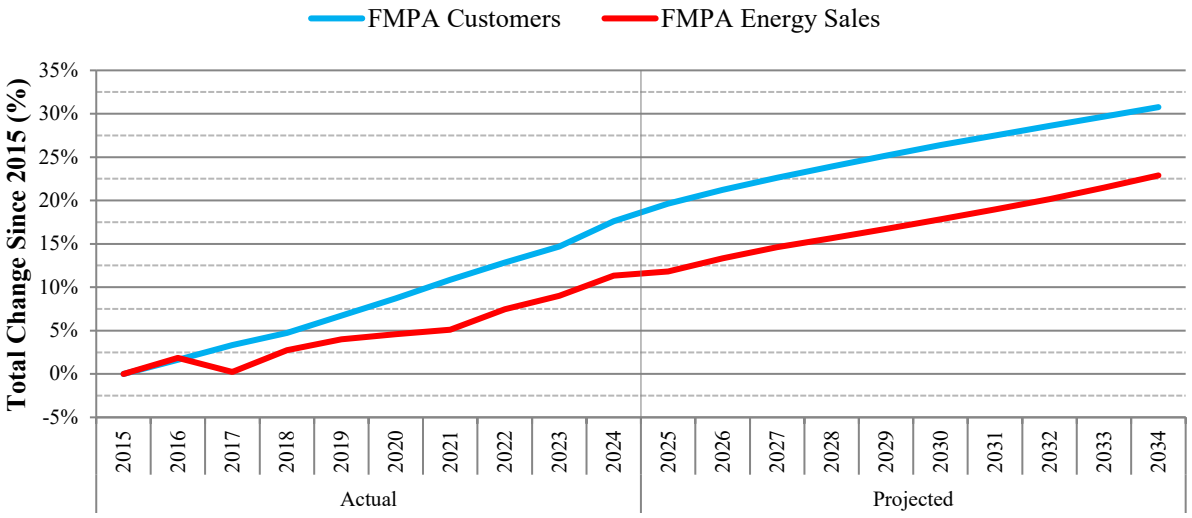
FMPA's annual increase in energy sales was 2.1 percent in 2024, higher than the 1.5 percent increase recorded in 2023. According to the Utility, this is due to an increase in seasonal firm capacity and energy sales that did not take place in the year prior.

FMPA noted that, in aggregate, its UPC has been relatively flat in both the residential and non-residential sectors after controlling for weather variation from normal conditions. The Utility noted that a continued orientation toward conservation and continued improvement in energy efficiency, driven primarily from technological advances, equipment standards, and enhanced building codes, place downward pressure on average usage.

FMPA acknowledged that, over the last several years, EVs adoption has steadily increased in Utility's service areas. Given the significance of this trend, FMPA's 2025 load forecast includes a projection of the future impact of EV charging energy.

For the current 10-year forecast horizon, FMPA is projecting an average annual growth rate of approximately 1.0 percent for its customer base, and a 1.1 percent average annual growth rate for energy sales. Figure 30 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FMPA filed in its 2025 TYSP.

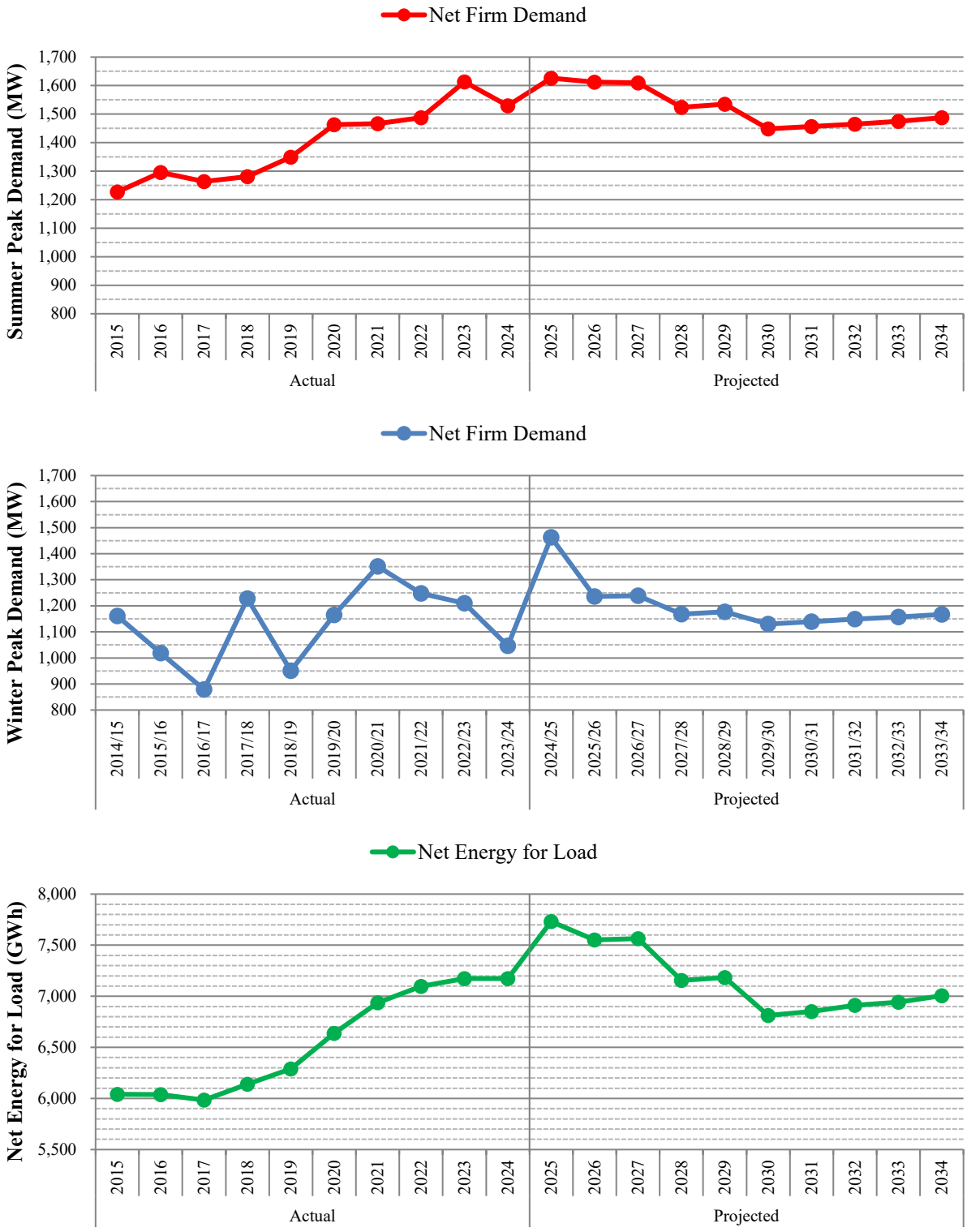
Figure 30: FMPA Growth



Source: 2025 TYSP

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years 2015 through 2024 and forecast years 2025 through 2034. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer DSM programs, the impacts of which are included in the graphs.

Figure 31: FMPA Demand and Energy Forecasts



Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 18 shows FMPA's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. FMPA uses natural gas as its primary fuel, producing 85 percent of energy in 2024 and increasing to 90 percent of energy by 2034. FMPA projects to end energy generation from coal beginning in 2028 with the conversion of the Stanton Energy Center Unit 2 from coal to natural gas-fired generation. Overall, coal-generated energy is being replaced by a combination of increased natural gas, nuclear, and renewable energy sources.

Table 18: FMPA Energy Generation by Fuel Type

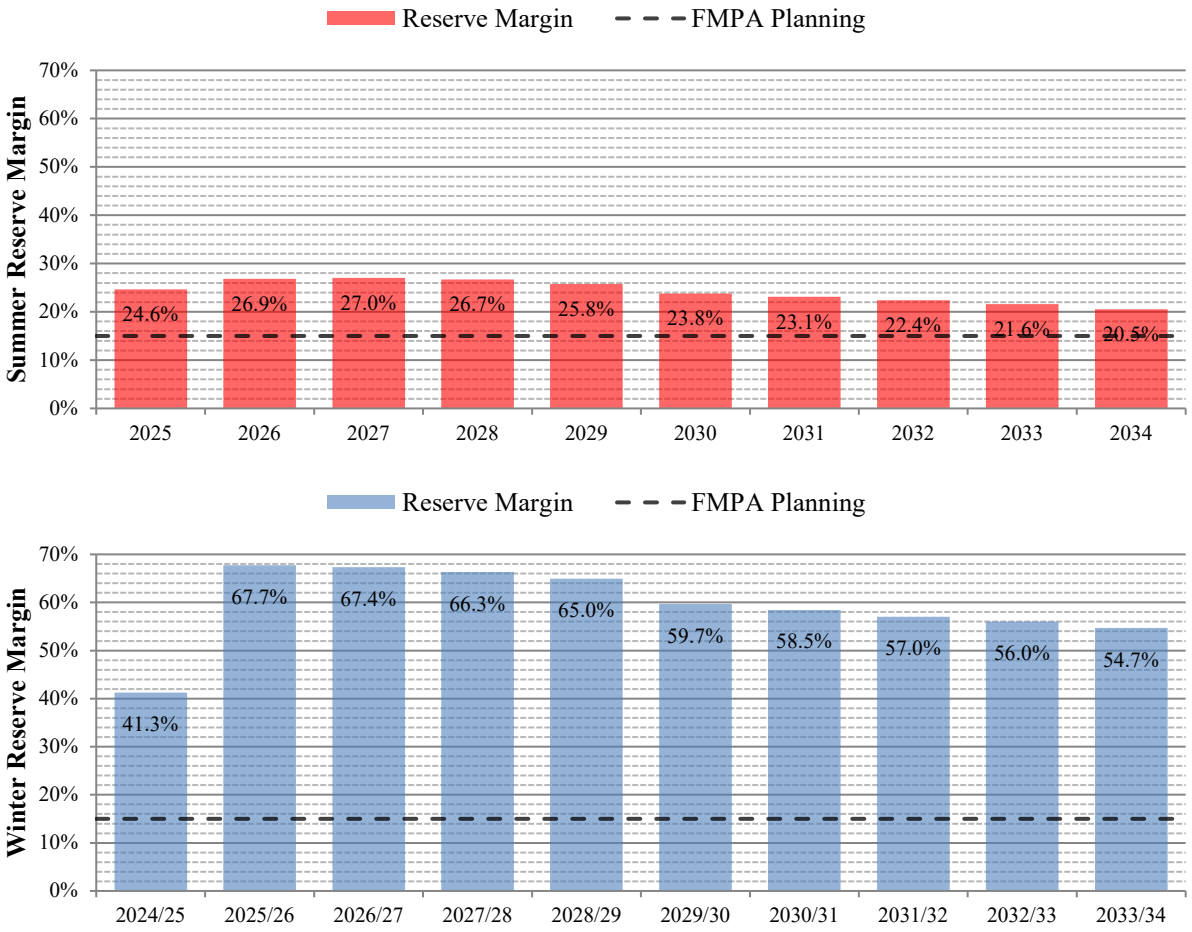
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	6,073	84.7%	6,275	89.6%
Coal	582	8.1%	0	0.0%
Nuclear	353	4.9%	390	5.6%
Oil	3	0.0%	1	0.0%
Renewable	161	2.2%	340	4.9%
Interchange	0	0.0%	0	0.0%
NUG & Other	0	0.0%	0	0.0%
Total	**7,172**		**7,006**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 32 displays the forecast planning reserve margin for FMPA through the planning period for both seasons. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 32: FMPA Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

FMPA plans on retiring and adding one unit each during the planning period, as illustrated in Table 19. The Stanton Energy Center Unit 1, a coal steam unit which is jointly owned with OUC and others, is scheduled for retirement in 2025. In 2028, the Stanton Energy Center Unit 2 is scheduled for conversion from a coal-fired to a natural gas-fired steam unit. FMPA is acquiring the existing Orange Cogeneration 104 MW natural gas-fired combined cycle merchant facility in 2026. In addition to its utility-owned generation, FMPA has entered into multiple purchased power agreements (PPAs) for additional solar capacity.

Table 19: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Energy Center Unit 1	ST BIT	118	Jointly Owned Unit
		Total Retirements	**118**	
New Units				
2026	Bartow Energy Center	CC NG	104	Merchant Acquisition
		Total New Units	**104**	
		Net Additions	**(14)**	

Source: 2025 TYSP

Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility by sales required to file a TYSP. The Utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

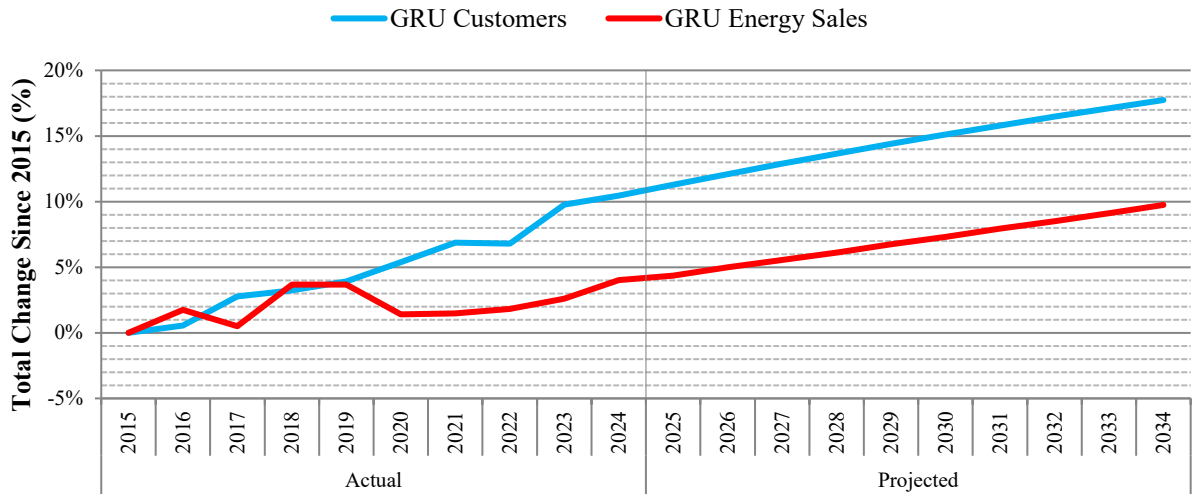
In 2024, GRU had approximately 104,510 customers and annual retail energy sales of 1,836 GWh, accounting for approximately 0.8 percent of Florida's annual retail energy sales. In the same year, the Utility's total customer growth and total retail sales growth were approximately 0.6 percent and 1.4 percent, respectively. Over the last 10 years, GRU's customer base has increased by approximately 10.4 percent with an annual growth rate of 1.1 percent, while retail energy sales have increased by approximately 4.0 percent with an annual growth rate of 0.4 percent.

Over the past 10 years, GRU's residential UPC declined approximately 0.2 percent per year, while its non-residential UPC declined approximately 0.8 percent per year. Some of the factors that influence these UPC declines include energy efficiency standards, improved building codes, increasing electricity prices, and growing participation in behind-the-meter solar energy. For the forecast period, GRU projected its residential UPC will remain flat. In the non-residential sectors, increasing real price of electricity is projected to play a large role such that UPC will decline at a rate of approximately 0.2 percent per year.

For the current 10-year forecast horizon, GRU's number of customers and retail energy sales will both grow nearly the same at an annual average rate of approximately 0.6 percent. The Utility indicated that its projected growth of retail energy sales is supported by its projected increase in the number of customers and offset negatively by flat or declining UPC.

Figure 33 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that GRU filed in its 2025 TYSP.

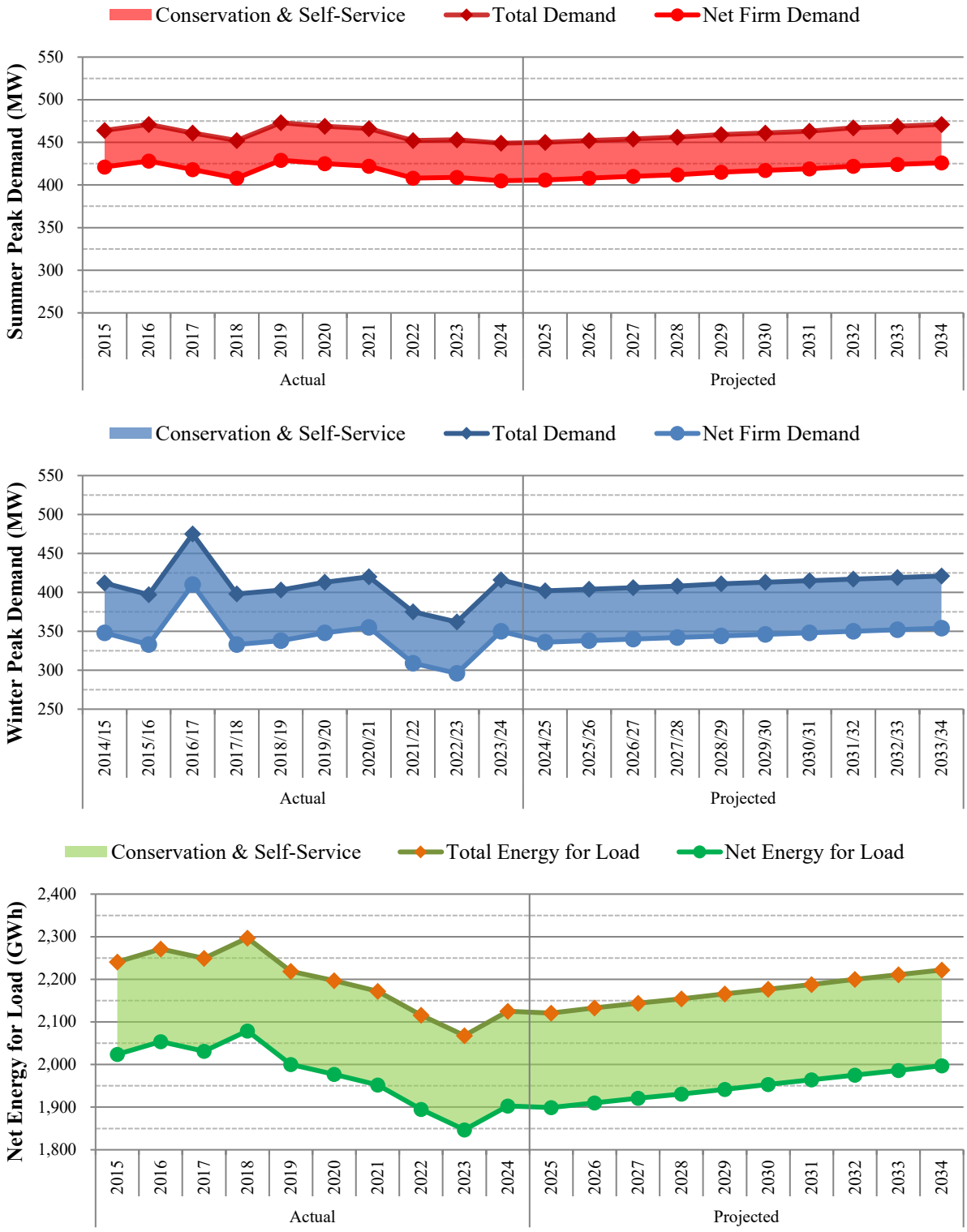
Figure 33: GRU Growth



Source: 2025 TYSP

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 34 include the impact of these DSM programs.

Figure 34: GRU Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 20 shows GRU's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. GRU relies primarily upon natural gas for energy generation, making up 82 percent of net energy for load in 2024. GRU is projected to use natural gas for less than half of its energy generation by 2034. Only three utilities, FPL, GRU, and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2034, natural gas will remain GRU's primary fuel source at 48 percent, while renewables will account for 33 percent. Coal generation is anticipated to increase from approximately 0 percent in 2024 to 16 percent in 2034, with the increase being associated with the co-firing of coal and natural gas at Deerhaven Unit FS02, GRU's only remaining unit capable of burning coal.

Table 20: GRU Energy Generation by Fuel Type

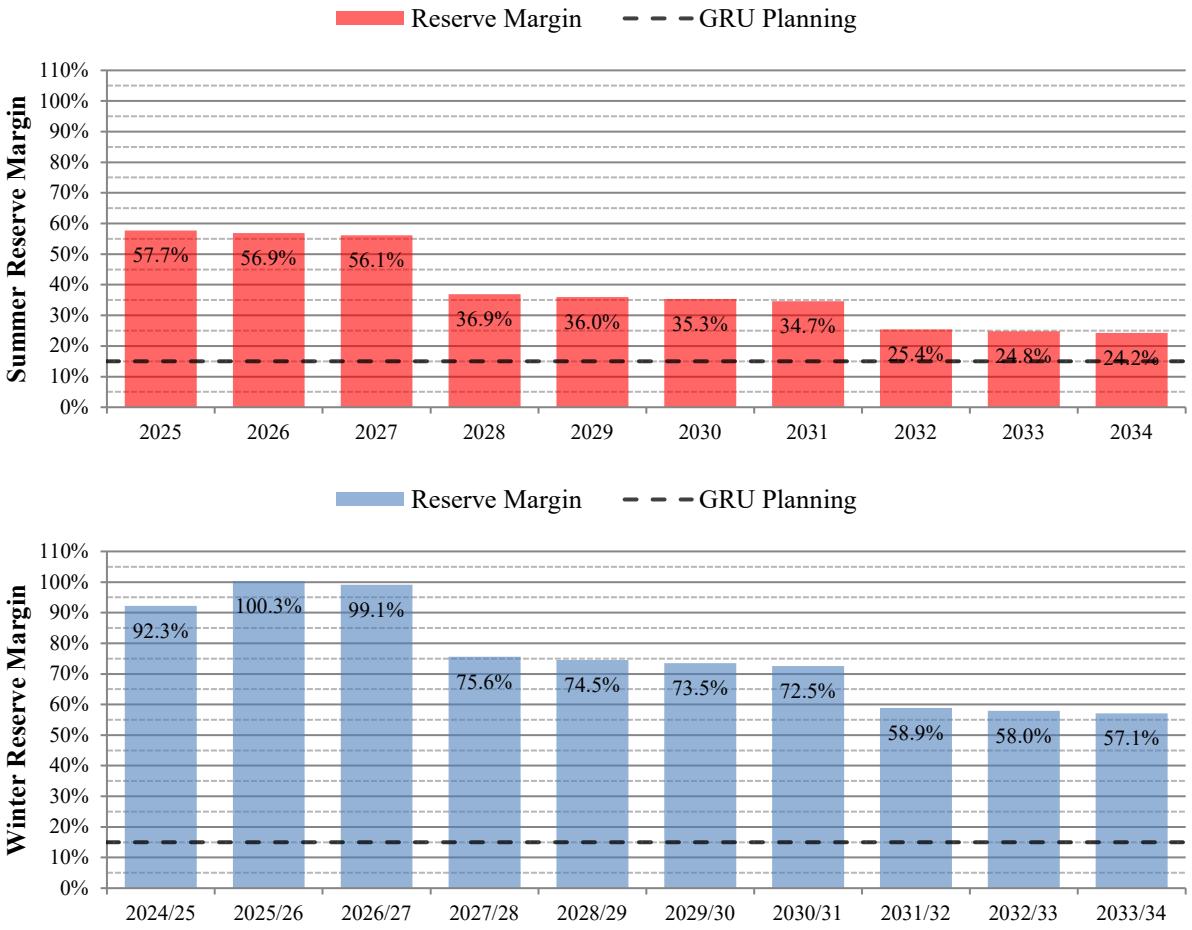
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	1,562	82.1%	959	48.0%
Coal	2	0.1%	316	15.8%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	253	13.3%	654	32.7%
Interchange	0	0.0%	0	0.0%
NUG & Other	86	4.5%	68	3.4%
Total	**1,903**		**1,997**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 displays the forecast planning reserve margin for GRU through the planning period for both seasons. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period.

Figure 35: GRU Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

GRU currently plans on retiring three natural gas-fired units, as described in Table 21. All three units, a pair of combustion turbines and a steam turbine, are located at GRU's Deerhaven plant.

Table 21: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2027	Deerhaven Unit FS01	ST NG	76	
2031	Deerhaven Unit GT01 & GT02	GT NG	35	2 Units
		Total Retirements	**111**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(111)**	

Source: 2025 TYSP

JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2025 TYSP suitable for planning purposes.

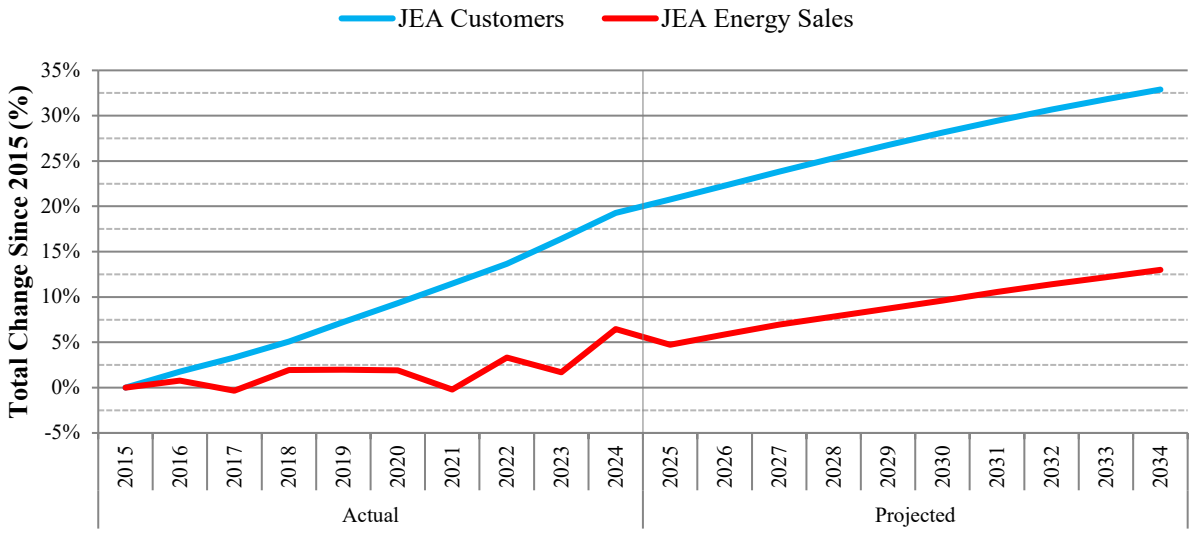
Load & Energy Forecasts

In 2024, JEA had approximately 527,491 customers and annual retail energy sales of 12,873 GWh, accounting for approximately 5.2 percent of Florida's annual retail energy sales. Over the last 10 years, JEA's customer base has increased by approximately 19.3 percent, while retail energy sales have increased by approximately 6.5 percent.

JEA indicated that the utility-funded DSM programs continue to be a contributor to the decrease in residential UPC. The other contributing factors include customer behavioral changes, increased electric rates, and more multifamily housing construction (such housing features lower UPC compared to single-family housing). The Utility noted that the U.S. Government's SEER Requirement Changes for 2015 requiring new split system central air conditioners to be a minimum 14 SEER was the primary reason for the decrease in electricity UPC in years subsequent to the new standard. The Utility further indicated that the new 2023 SEER rating standards, now requiring new air conditioners in southern states to be a minimum 15 SEER, will continue to contribute to the decrease in electricity UPC. For the 2025 TYSP forecasting horizon, JEA expects that residential UPC will stay flat with an average growth rate of 0.4 percent, commercial UPC will decrease by 1.1 percent per year, and industrial UPC will decrease by 0.2 percent per year.

For the next 10 years, JEA's customer base is forecasted to grow at an average annual rate of 1.1 percent; while its retail energy sales are projected to increase at an average annual rate of 0.9 percent. Figure 36 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that JEA filed in its 2025 TYSP.

Figure 36: JEA Growth



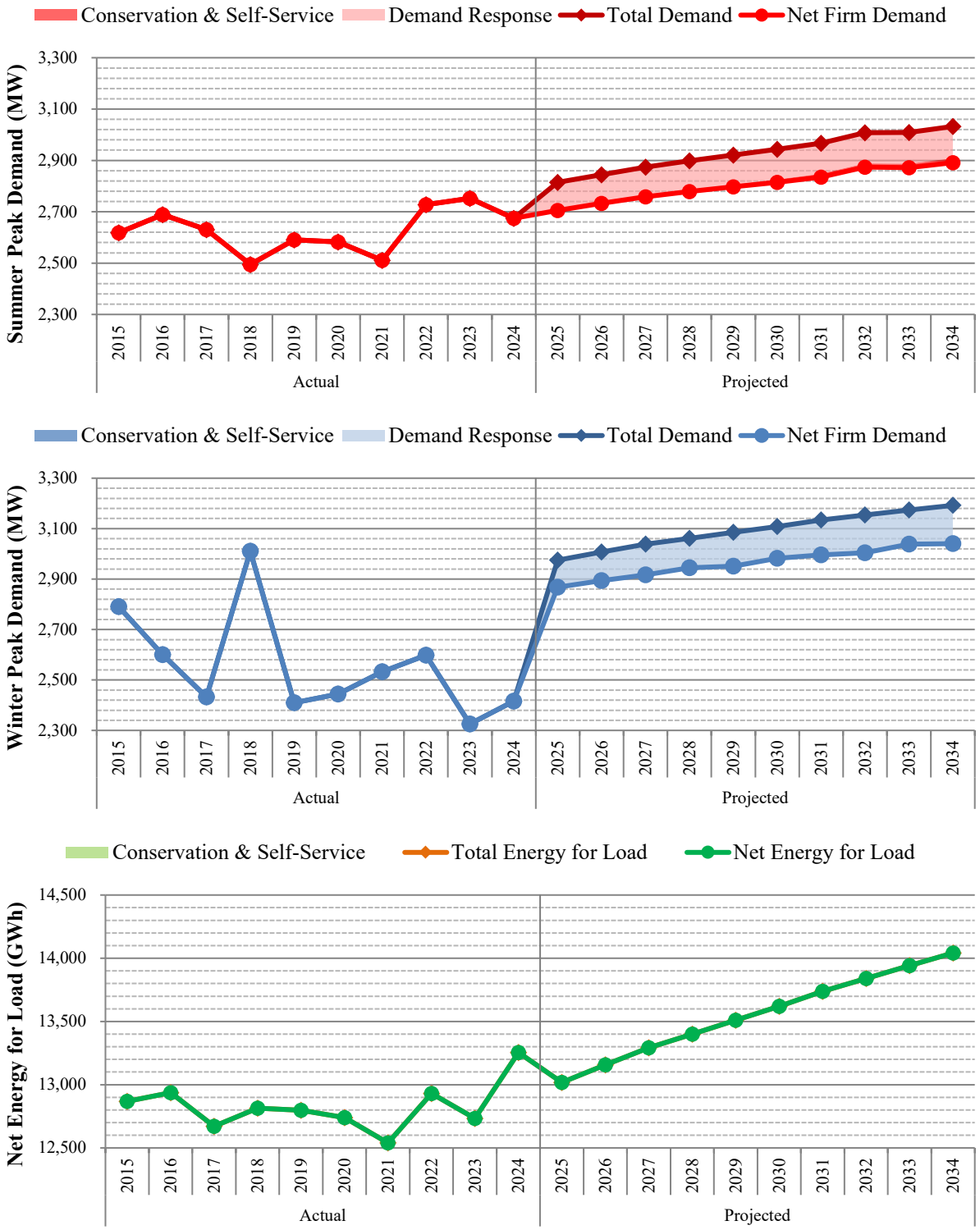
Source: 2025 TYSP

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. Even though JEA is a municipal utility, it is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. These graphs include the full impact of DSM, and assume that all available demand response resources will be activated during the seasonal peak. The Commission reviewed and established energy conservation goals for JEA and approved JEA's 2025-2034 DSM Plan.[19,20] In preparing its 2025 TYSP seasonal peak demand and energy forecasts, JEA reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 37.

[19] Order No. PSC-2024-0432-FOF-EG, issued September 20, 2024, in Docket No. 20240016-EI, *In re: Commission review of numeric conservation goals (JEA)*.

[20] Order No. PSC-2025-0094-PAA-EG, issued March 24, 2025, in Docket No. 20240167-EG, *In re: Petition for approval of demand-side management plan, by JEA*.

Figure 37: JEA Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 22 shows JEA's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. While natural gas was the dominant fuel source in 2024, purchases from other utilities, through the Interchange, was JEA's second most utilized energy source. JEA has the highest percentage of energy from other utilities, primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the Vogtle nuclear Units 3 and 4. JEA is projected to reduce its Interchange purchases from approximately 28 percent in 2024 to 15 percent in 2034, primarily offset by an increase in renewables, which will represent 20 percent of energy by 2034.

Table 22: JEA Energy Generation by Fuel Type

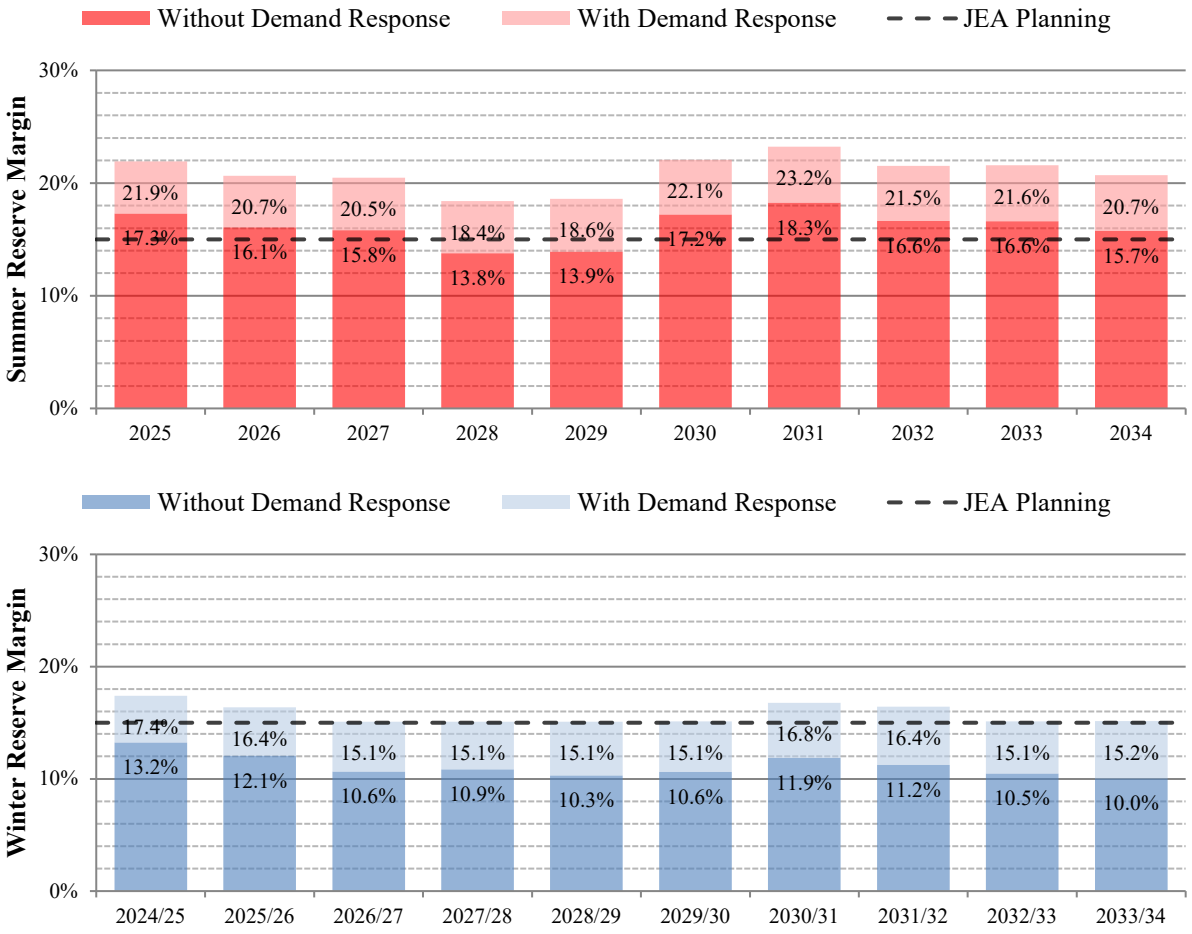
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	8,257	62.3%	8,172	58.2%
Coal	774	5.8%	986	7.0%
Nuclear	0	0.0%	0	0.0%
Oil	8	0.1%	9	0.1%
Renewable	507	3.8%	2,832	20.2%
Interchange	3,676	27.7%	2,044	14.6%
NUG & Other	32	0.2%	0	0.0%
Total	**13,254**		**14,043**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned PPA with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. Over the planning horizon, JEA's winter reserve margin is lower than its summer reserve margin.

Figure 38: JEA Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

JEA projects one unit retirement and one unit addition during the planning period, as described in Table 23. JEA plans on retiring Northside Unit 3 and adding an unnamed natural gas-fired combined cycle unit in 2030. The unnamed combined cycle would be subject to PPSA approval and it is anticipated a filing with the Commission would occur in 2026. JEA also includes in its resource planning PPAs with 18 solar facilities totaling 1,129 MW, including 2 with collocated batteries totaling 100 MW, over the planning period.

Table 23: JEA Energy Generation by Fuel Type

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2030	Northside Unit 3	ST NG	524	
		Total Retirements	**524**	
New Units				
2030	Advanced-Class 1x1 CC	CC NG	576	PPSA Approval Needed
		Total New Units	**576**	
		Net Additions	**52**	

Source: 2025 TYSP

Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a TYSP. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

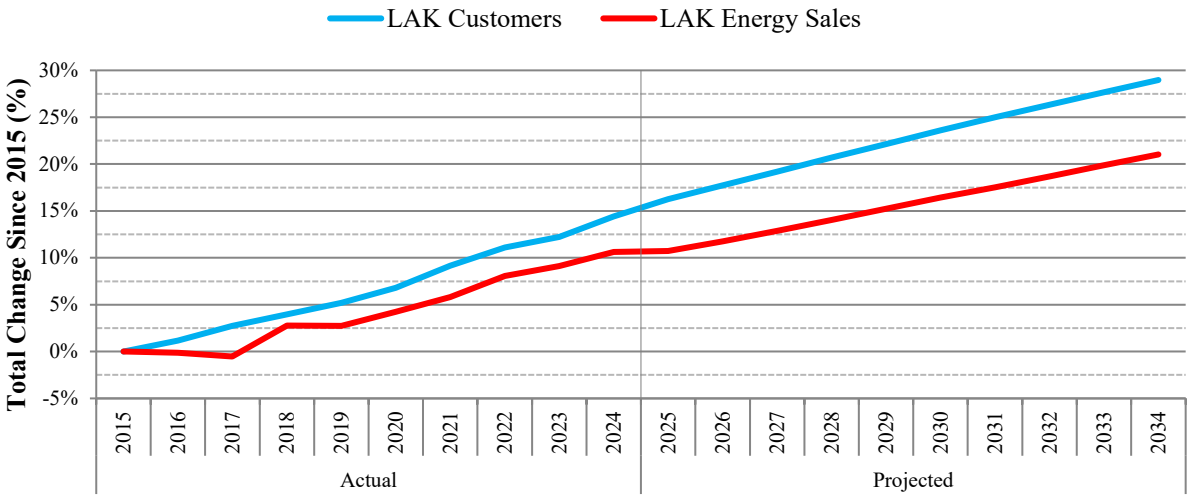
In 2024, LAK had approximately 143,790 customers and annual retail energy sales of 3,356 GWh, accounting for approximately 1.4 percent of Florida's annual retail energy sales. In the same year, the Utility's total customer growth and total retail sales growth were approximately 1.9 percent and 1.4 percent, respectively. Historically, the Utility has experienced a steady growth in residential and commercial customers due to a rise in population in the Lakeland area. The number of industrial customers are relatively stable with most industry being manufacturing or distribution centers. Over the last 10 years, LAK's customer base has increased by 14.4 percent, while retail energy sales have grown by approximately 10.6 percent.

LAK's residential UPC has slightly increased as more customers continue to work from home, leading to higher daytime energy consumption which is an ongoing trend that emerged following the COVID-19 pandemic. Both LAK's commercial and industrial UPCs decreased slightly which is attributed to energy efficient buildings and appliances. Additionally, customer's movement to rooftop solar has contributed in offsetting the energy usage from the grid. LAK projects that the UPC of each rate class and the total UPC will continue to decrease, and perceived that the factors contributing to the decline is appliance efficiency improvement and new homes being built to be more efficient.

For the next 10 years, LAK's forecasts indicate that its number of customers are projected to grow at an average annual rate of approximately 1.2 percent, and its retail energy sales are projected to grow at an average annual rate of approximately 1.0 percent. The Utility identified the factors contributing to the growth of sales are continuous population increase and economic development. Also contributing to the sales growth is the warmer weather expected.

Figure 39 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that LAK filed in its 2025 TYSP.

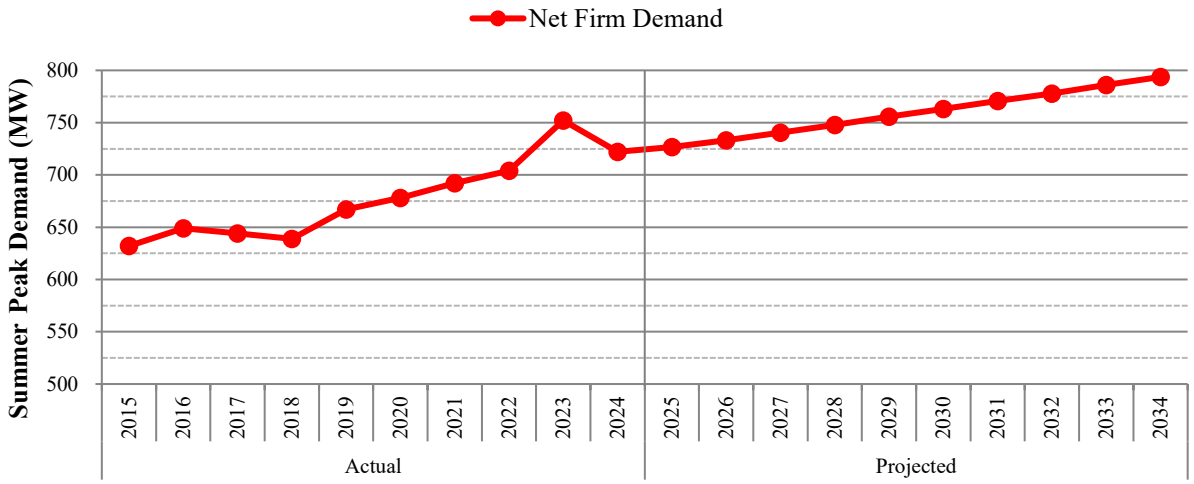
Figure 39: LAK Growth

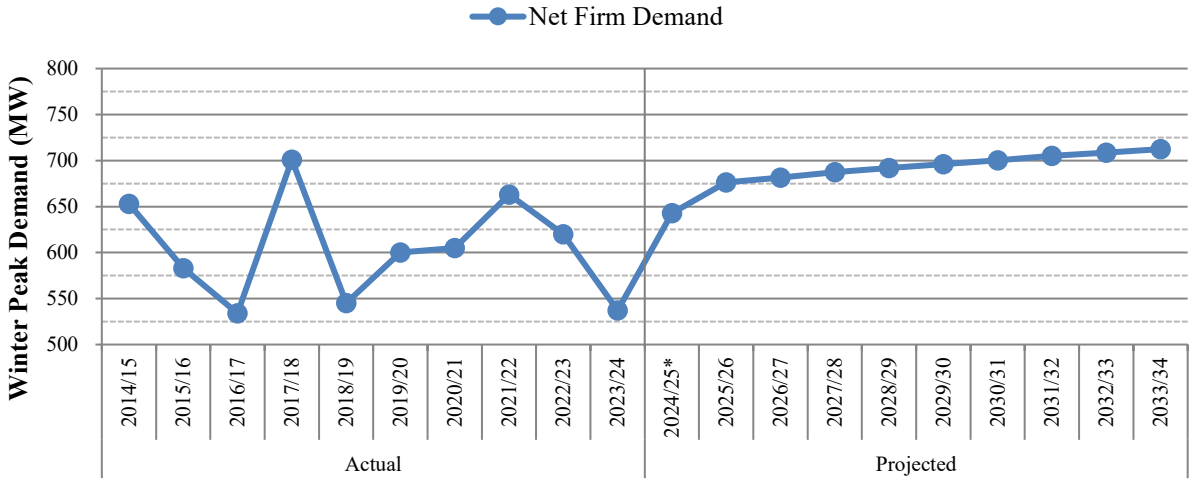


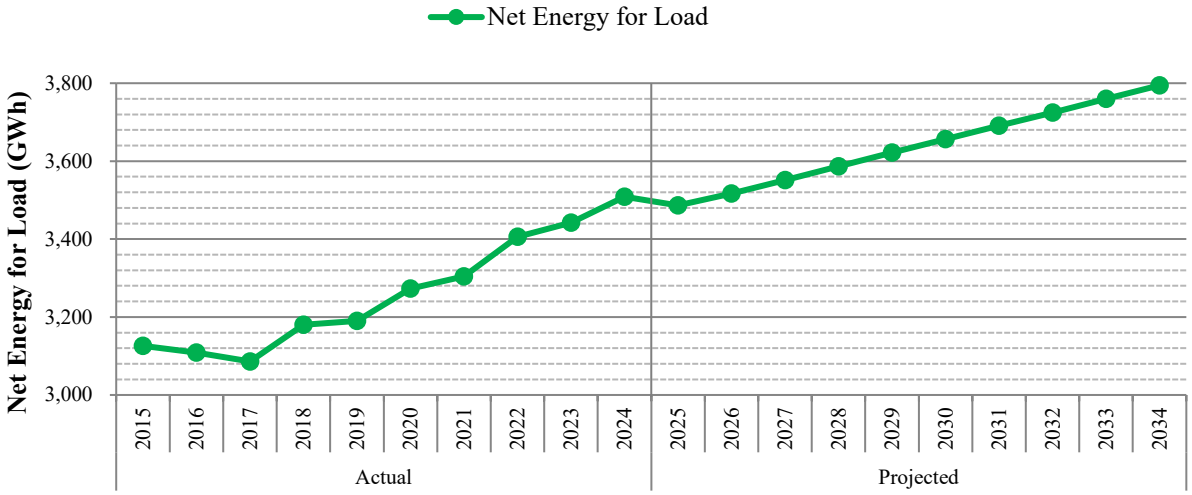
Source: 2025 TYSP

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 40: LAK Demand and Energy Forecasts







Source: 2025 TYSP

Fuel Diversity

Table 24 shows LAK's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. LAK uses natural gas as its primary fuel type for energy, 75 percent in 2024, with purchases (listed in the NUG & Other category) representing 24 percent net energy for load, and the remaining 1 percent from renewables. By 2034, natural gas is expected to be reduced to 64 percent, offset by purchases and renewables, which would represent 31 and 5 percent, respectively. LAK, in the actual and projected period, is the utility most reliant upon energy purchases.

Table 24: LAK Energy Generation by Fuel Type

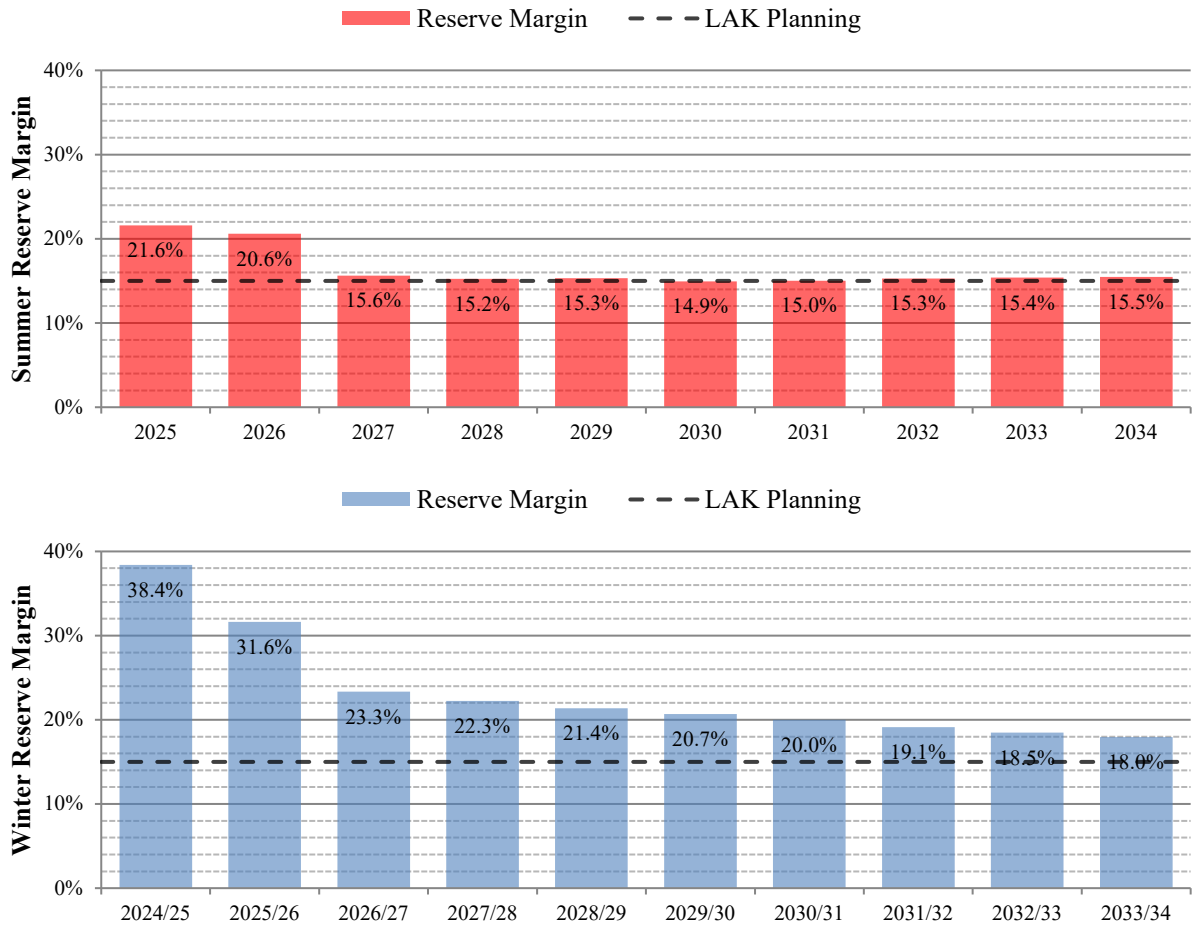
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	2,643	75.3%	2,408	63.5%
Coal	0	0.0%	0	0.0%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	28	0.8%	194	5.1%
Interchange	0	0.0%	0	0.0%
NUG & Other	838	23.9%	1,192	31.4%
Total	**3,509**		**3,794**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 displays the forecast planning reserve margin for LAK through the planning period for both seasons. LAK does not offer demand response programs at this time. As illustrated by Figure 41, summer peak demand is the controlling factor for reliability planning for almost all years of the planning period.

Figure 41: LAK Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

LAK projects three unit additions during the planning period, as described by Table 25. The additions are all natural gas-fired internal combustion engines, with a capacity of 20 MW and an in-service date of 2025. Three similar units entered service in 2024. LAK is in negotiations for a PPA with Edge Solar for a 74.8 MW solar facility by 2026. None of these additions requires a need determination pursuant to the PPSA.

Table 25: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
		Total Retirements	**0**	
New Units				
2025	McIntosh Units MREP 1-3	IC NG	60	3 Units
		Total New Units	**60**	
		Net Additions	**60**	

Source: 2025 TYSP and Data Responses

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's sixth largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

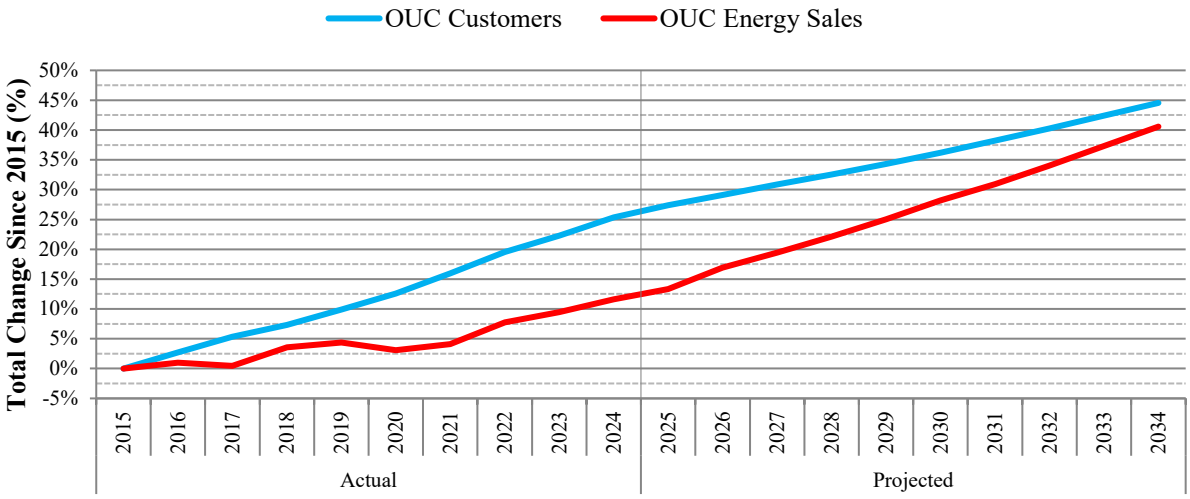
In 2024, OUC had approximately 282,179 customers and annual retail energy sales of 7,295 GWh, accounting for approximately 3.0 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 25.4 percent, while its retail energy sales have increased by 11.6 percent, approximately.

OUC acknowledged that over the past 10 years, its UPC has been essentially flat for both the residential and commercial customer segments. For the next 10 years, OUC's residential UPC is expected to grow 1.9 percent annually. The main driver of this increase is the projected adoption of EVs. The Utility's commercial UPC is expected to grow 1.2 percent annually. This increase is driven by large customer expansions which increase overall commercial sales.

Over the forecast horizon, OUC is projecting growth in the number of customers at an average annual rate of 1.4 percent, and growth in retail energy sales at an average annual rate of 2.4 percent, approximately. The Utility indicates that this projected increase is driven by large commercial expansions and residential EV adoption.

Figure 42 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that OUC filed in its 2025 TYSP.

Figure 42: OUC Growth

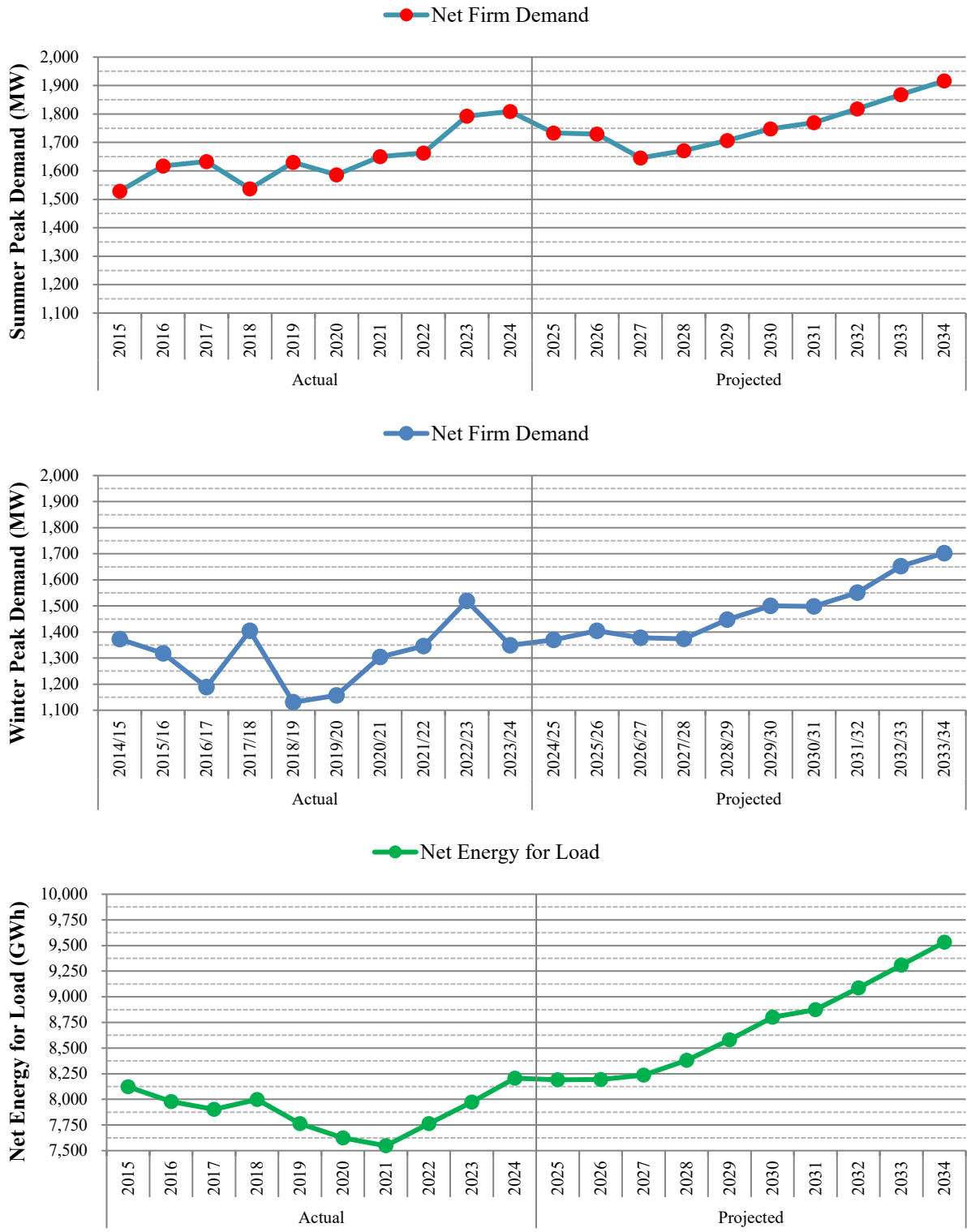


Source: 2025 TYSP

The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the impact of the Utility's DSM programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption. The Commission reviewed and established energy conservation goals for OCU and approved OUC's 2025-2034 DSM Plan.[21,22] In preparing its 2025 TYSP seasonal peak demand and energy projects, OUC reflects these Commission-approved FEECA goals will be extended through the forecast period (through 2034), as shown in Figure 43.

[21] Order No. PSC-2024-0433-FOF-EG, issued September 20, 2024, in Docket No. 20240017-EI, *In re: Commission review of numeric conservation goals (Orlando Utilities Commission)*.
[22] Order No. PSC-2025-0086-PAA-EG, issued March 24, 2025, in Docket No. 20240166-EG, *In re: Petition for approval of 2025 demand-side management plan, by Orlando Utilities Commission*.

Figure 43: OUC Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. In 2024, approximately 70 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met approximately 20 percent of the demand. By 2034, OUC will be one of three utilities, along with FPL and GRU, to use natural gas for less than half of its energy generation, and the only utility to use renewable energy for a majority of its energy generation.

Table 26: OUC Energy Generation by Fuel Type

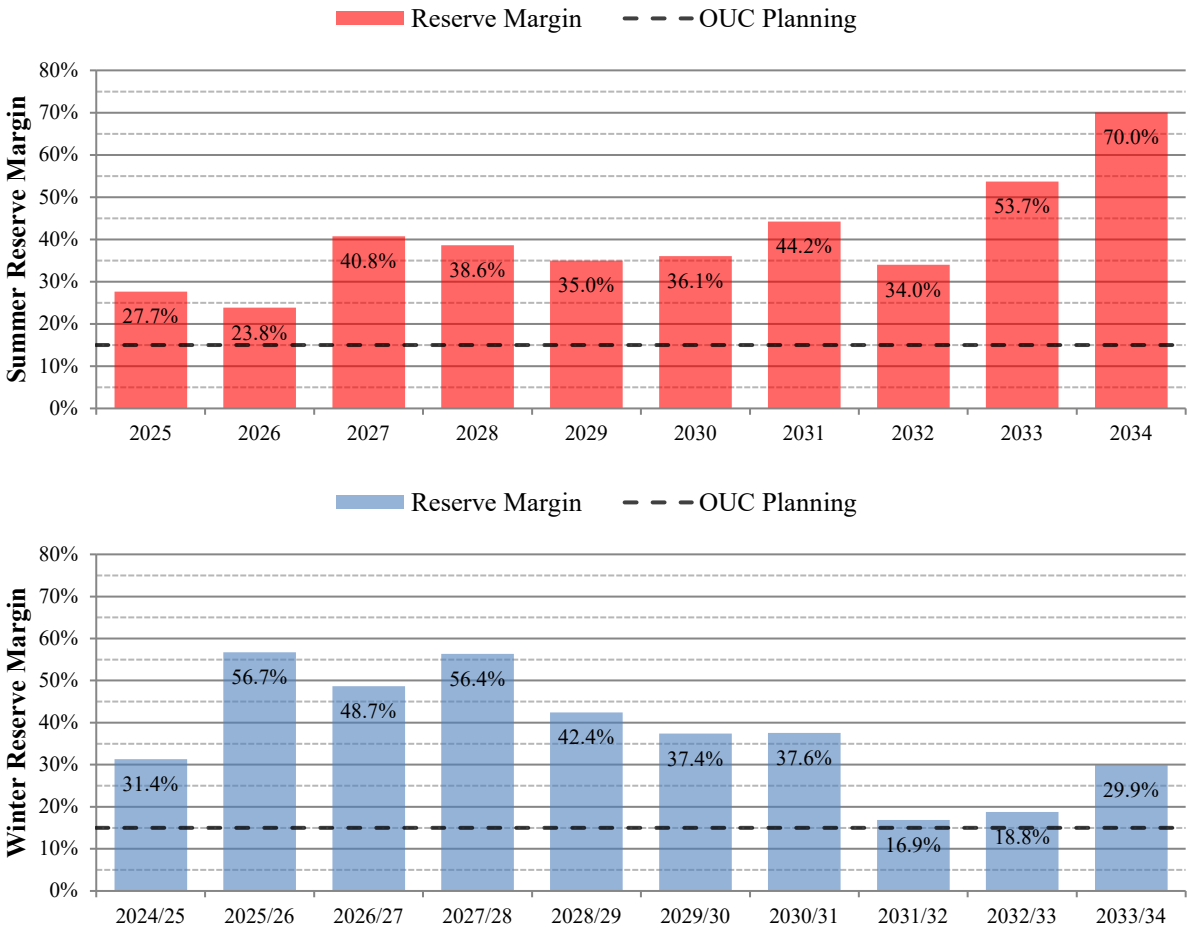
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	5,753	70.1%	4,230	44.4%
Coal	1,608	19.6%	0	0.0%
Nuclear	433	5.3%	511	5.4%
Oil	4	0.0%	0	0.0%
Renewable	408	5.0%	4,791	50.3%
Interchange	0	0.0%	0	0.0%
NUG & Other	0	0.0%	0	0.0%
Total	**8,206**		**9,532**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 44 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of DSM programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand.

Figure 44: OUC Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

OUC projects one unit retirement during the planning period, as described in Table 27. OUC plans on retiring Stanton Energy Center Unit 1, a jointly owned unit with FMPA and other utilities, in 2025. OUC is also converting its last remaining coal-fired Stanton Energy Center Unit 2 to a natural gas-fired unit in 2028. Transmission upgrades planned for 2025 and 2026 will allow OUC full access to the firm capacity of its existing three natural gas-fired combustion turbines acquired from the Osceola merchant plant, for a total of 471 MW. OUC also includes in its resource planning PPAs with several solar and battery facilities, including a total of 1,490 MW of solar and 800 MW of batteries over the planning period.

Table 27: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Energy Center Unit 1	ST BIT	311	Jointly Owned Unit
		Total Retirements	**311**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(311)**	

Source: 2025 TYSP

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member distribution cooperatives and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

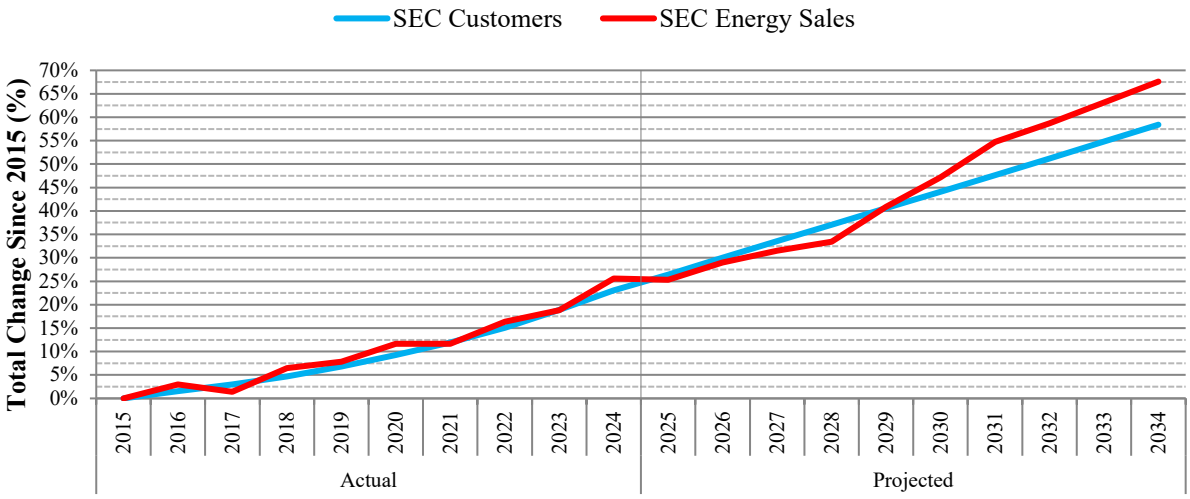
In 2024, SEC member cooperatives had approximately 925,329 customers and annual retail energy sales of 16,792 GWh, accounting for approximately 6.8 percent of Florida's annual retail energy sales. Over the last 10 years, SEC's customer base has increased by 23.1 percent, while its retail energy sales have increased by approximately 25.6 percent.

Over the past 10 years, for SEC's combined members (hereinafter the Membership), average UPC has remained relatively stable, with the residential sector increasing annually by 0.3 percent on average, and the commercial sector decreasing annually by 0.4 percent on average. These trends reflect the widespread adoption of more efficient residential and commercial appliances and equipment. For the next 10 years, across the Membership, the UPC is expected to increase by 2.4 percent annually in average, with diverging trends by customer type. Residential UPC is expected to decrease by 0.9 percent and commercial UPC is expected to increase by 3.2 percent annually. The forecasted slight decline in residential UPC is due primarily to the continued replacement of older appliances and equipment with more energy-efficient models. In contrast, the projected increase in commercial UPC is due to the expectation of more energy-intensive customers, which offset any efficiency-driven declines.

Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 2.5 percent. The major factors contributing to the growth are continued positive net migration and growth in regional housing. SEC's projected average annual growth rate in retail energy sales is 3.3 percent.

Figure 45 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that SEC filed in its 2025 TYSP.

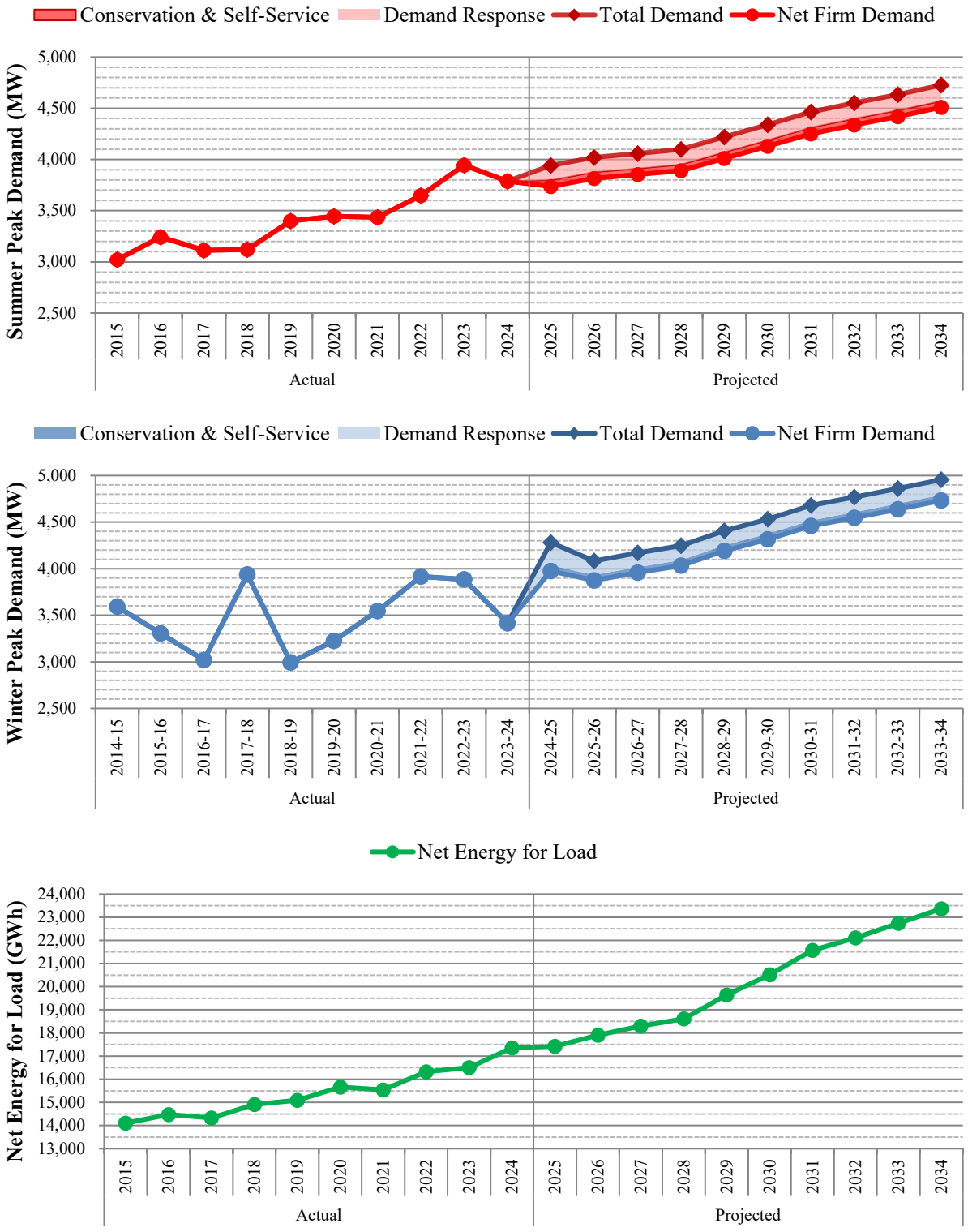
Figure 45: SEC Growth



Source: 2025 TYSP

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years 2015 through 2024 and forecast years 2025 through 2034. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer DSM programs, the impacts of which are included in Figure 46.

Figure 46: SEC Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 28 shows SEC's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. In 2024, natural gas was SEC's primary fuel, at 62 percent, with purchases making up approximately 20 percent, the second highest in the state. During the planning period, SEC is projected to increase its self-generation, primarily of natural gas, offsetting these purchases and coal generation. By 2034, natural gas will represent approximately 85 percent of SEC's fuel usage.

Table 28: SEC Energy Generation by Fuel Type

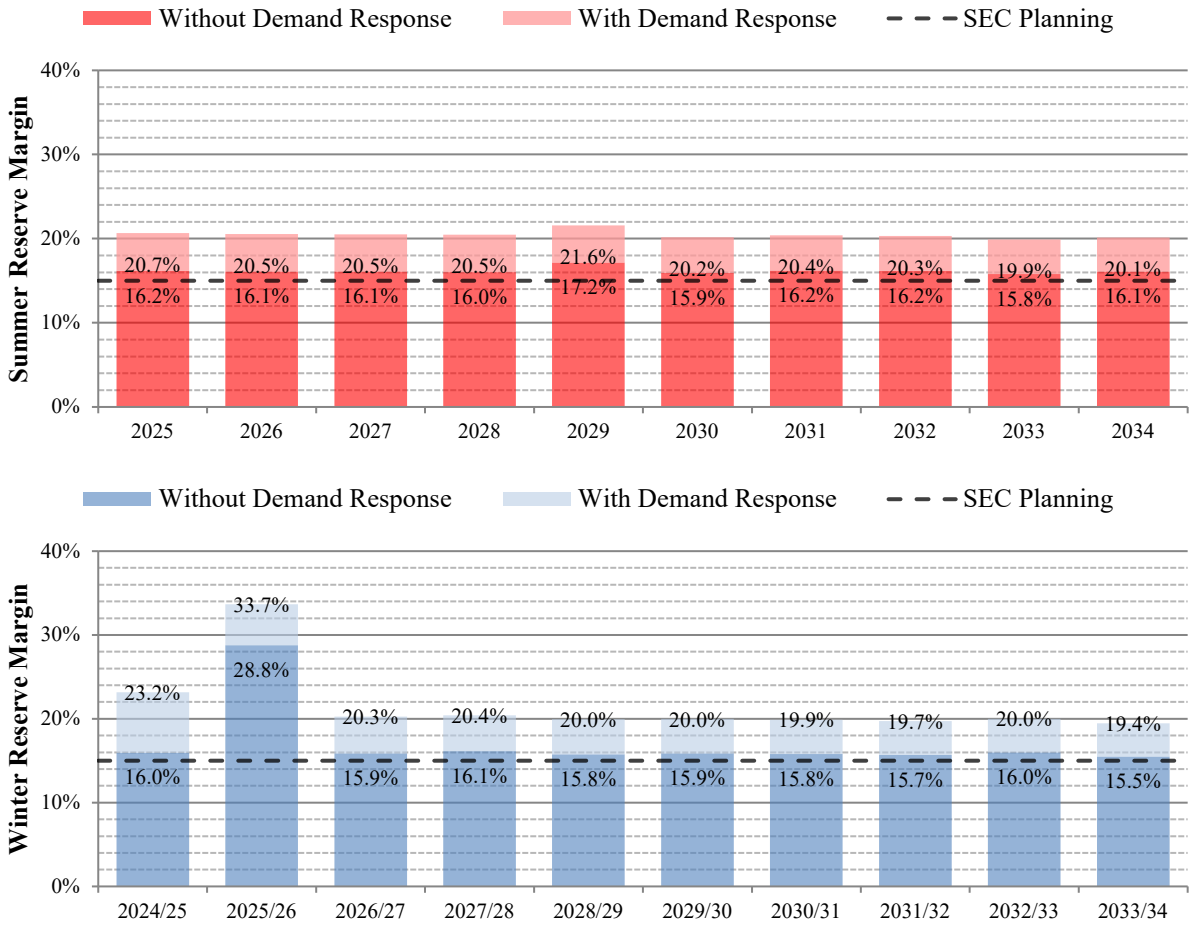
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	10,840	62.4%	19,781	84.6%
Coal	2,197	12.7%	1,965	8.4%
Nuclear	0	0.0%	0	0.0%
Oil	14	0.1%	6	0.0%
Renewable	383	2.2%	703	3.0%
Interchange	455	2.6%	0	0.0%
NUG & Other	3,470	20.0%	913	3.9%
Total	**17,359**		**23,368**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 47 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 47: SEC Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

SEC projects four unit additions during the planning period, as described by Table 29. All are natural gas-fired units, including two combined cycle and two simple cycle combustion turbines. The first combined cycle, the Shady Hills Energy Center in 2026, has already received PPSA approval by the Commission. The second combined cycle has a capacity of 559 MW, with an estimated in-service date of 2032. This unnamed combined cycle unit would be subject to PPSA approval and it is anticipated a filing with the Commission would occur in 2028.

Table 29: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
Total Retirements			**0**	
New Units				
2026	Shady Hills Energy Center Unit 1	NG CC	546	PPSA Approved
2028	Unnamed CT	NG CT	393	
2030	Unnamed CT	NG CT	393	
2032	Unnamed CC	NG CC	559	PPSA Approval Needed
Total New Units			**1,891**	
Net Additions			**1,891**	

Source: 2025 TYSP

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility by sales that files a TYSP. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, TAL had approximately 124,241 customers and annual retail energy sales of 2,788 GWh, or approximately 1.1 percent of Florida's annual retail energy sales. Over the last 10 years, TAL's customer base has increased by approximately 5.4 percent, while retail energy sales have increased by approximately 5.0 percent.

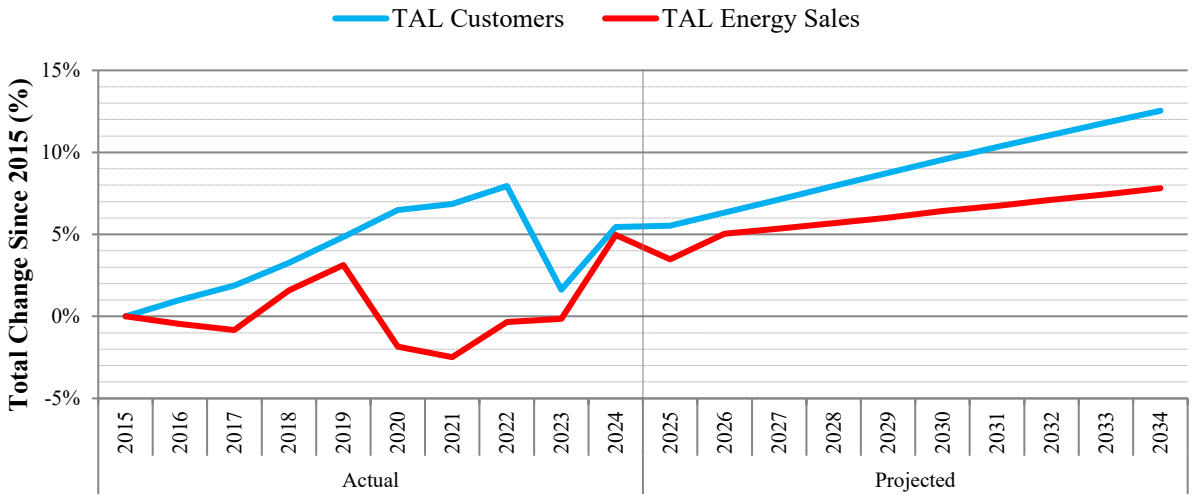
TAL noticed that, historically, both its residential and commercial UPC fluctuated slightly year-to-year but remained relatively steady over the 10-year period with one exception: a noticeable decrease for commercial customers in the year or two following the COVID-19 pandemic. Other major factors affecting UPC included growth in electrification (e.g., EV, customer-owned solar generation), market-driven efficiencies from upgrading HVAC, DSM incentives, and weather anomalies. Looking forward, TAL predicts that planning period trends in residential UPC will closely match the historical trends. The Utility indicates that the underlying economic factors that influence commercial growth in the planning period are often at odds with the gains from DSM and market-driven efficiencies. TAL is forecasting increased commercial activity, which will result in an increase in the commercial UPC, even with a slight offset from efficiency measures. The resulting trend in commercial UPC is increasing in the near future and then decreasing in later years as market-driven efficiencies and DSM measures build momentum over time.

In 2024, TAL's total customer growth and total retail sales growth are approximately 3.8 percent and 5.1 percent, respectively. Over the current forecast horizon, TAL is projecting an average annual growth rate of approximately 0.7 percent in its total customers, and an average annual growth rate of approximately 0.5 percent in its annual retail energy sales.

In 2023, TAL implemented new customer billing software, which changed the methodology of accounting for customer types and consolidated some service points. The resulting data anomaly showed an increase in average residential consumption, a decrease in average commercial consumption, and an overall reduction in service points. Since the software implementation is now complete, the Utility noted that its data collection issues should not persist on a going-forward basis. However, TAL indicates that with 2023 data remaining in the Utility's historical data as a step change, this anomaly or non-weather event-caused step change will continue to be noted in future reports.

Figure 48 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that TAL filed in its 2025 TYSP.

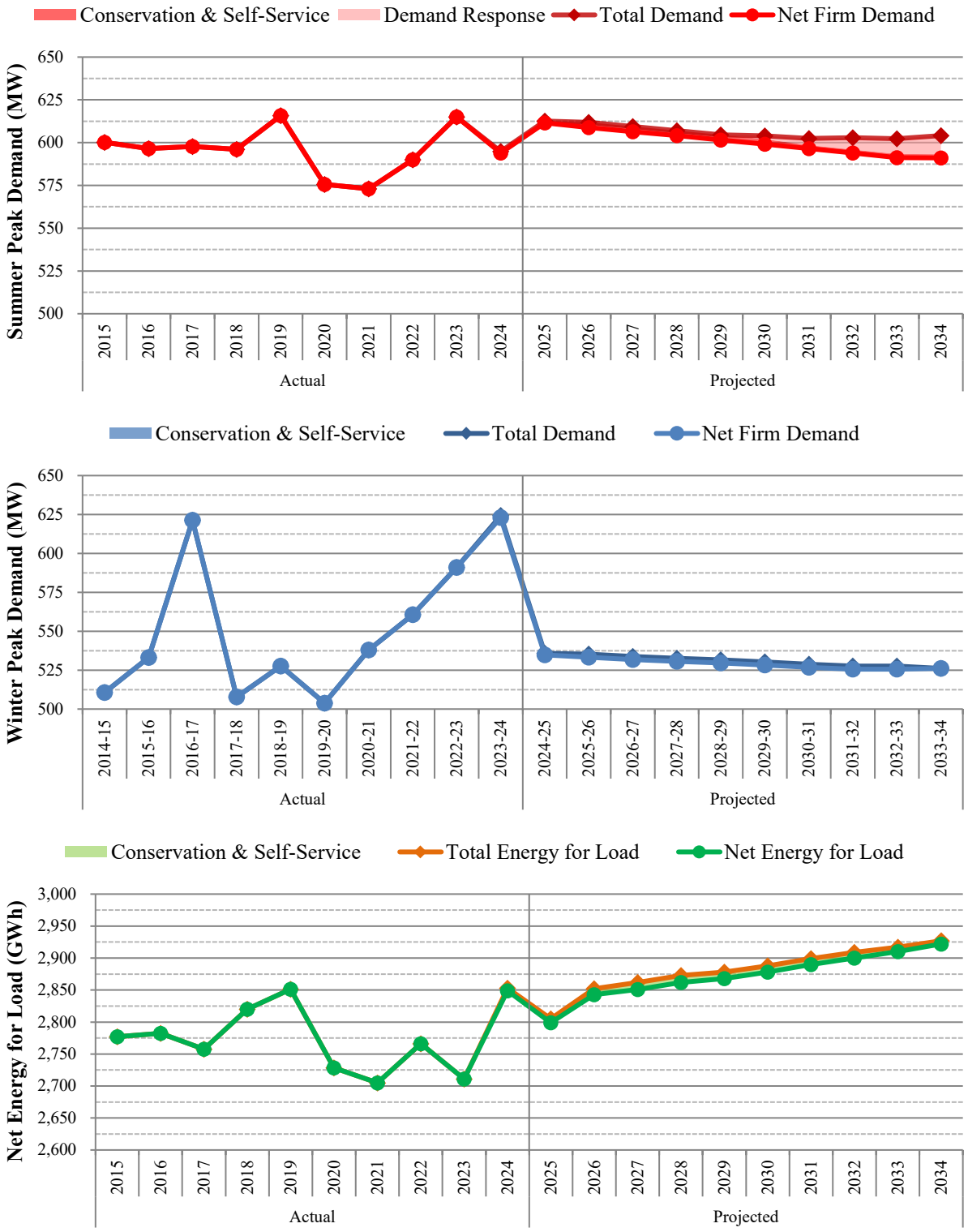
Figure 48: TAL Growth



Source: 2025 TYSP

The three graphs in Figure 49 show TAL's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the impact of DSM, and for future years reflect that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently, TAL only offers demand response programs that target appliances contributing to summer peak, and therefore have no effect upon winter peak.

Figure 49: TAL Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 30 shows TAL's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and QF. In 2024, TAL produced more energy than required for its native load and was a net exporter by approximately 8 percent, primarily of off-peak power during shoulder months due to its generation's operating characteristics. Natural gas is anticipated to remain the primary fuel source on the system and TAL will continue to be a net exporter of energy throughout the period.

Table 30: TAL Energy Generation by Fuel Type

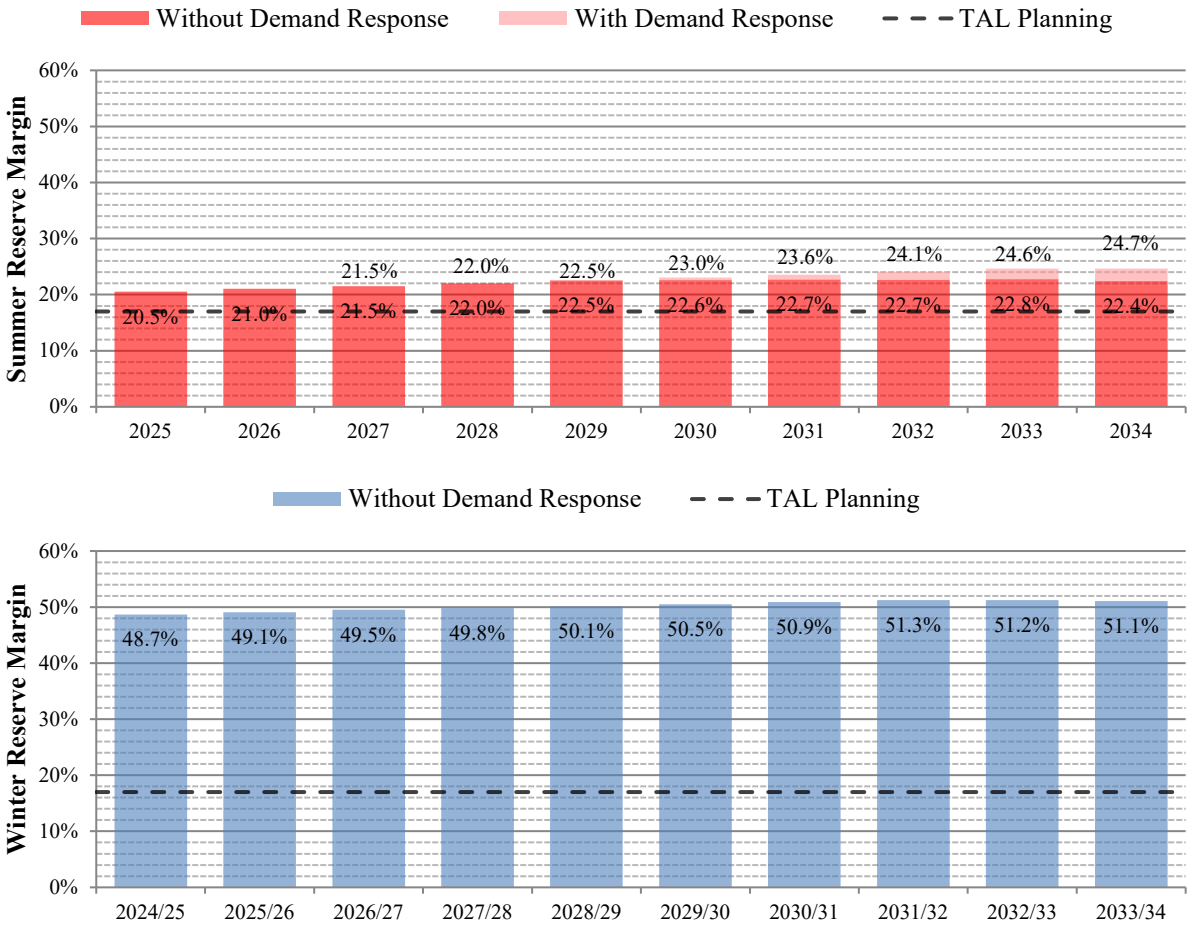
Fuel Type	Net Energy for Load			
	2024		2034	
	GWh	%	GWh	%
Natural Gas	2,985	104.8%	2,846	97.4%
Coal	0	0.0%	0	0.0%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	96	3.4%	111	3.8%
Interchange	0	0.0%	0	0.0%
NUG & Other	(232)	(8.1%)	(35)	(1.2%)
Total	**2,849**		**2,922**	

Source: 2025 TYSP and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 50 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 50: TAL Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

TAL plans no unit additions or retirements during the planning period.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 13

FRCC, 2025 REGIONAL LOAD & RESOURCE PLAN, FRCC-MS-PL-642

2025
Regional Load & Resource Plan
FRCC-MS-PL-642
Version: 1

3001 North Rocky Point Drive, Suite 410
Tampa, Florida 33607-8410
(813) 289-5644 - Phone
(813) 289-5646 - Fax
www.frcc.com

Classification: Public

The original signatures are maintained on file.

TITLE	NAME	DATE
Version Author	Michelle Poplin Reed	5/9/2025
Document Review Authority	Resource Subcommittee Load Forecast Working Group	5/28/2025
Document Owner/Approval Authority	Planning Committee	6/13/2025

Document Subject Matter Expert: Planning Technical Specialist
Original Author: Christina Rau
Responsible Department: Planning
Retention Period: 7 Years
File Name: frccmspl642_2025lrp
Document ID #: FRCC-MS-PL-642
Classification: Public

Introduction
FRCC Regional Load & Resource Plan

The Florida Reliability Coordinating Council (FRCC) annual Regional Load & Resource Plan (L&RP) is a collection of historical and forecasted planning information from electric utilities within the FRCC Region and the State of Florida. Data provided by the electric utilities is reflective of data contained in each of their annual Ten-Year Site Plan (TYSP) and/or their internal integrated resource planning documents. Section 186.801(1) of the Florida Statutes requires each electric utility within the State of Florida to submit to the Florida Public Service Commission (FPSC) a TYSP that estimates its power-generating needs and the general location of proposed power plant sites[1]. The Statute also states "TYSP shall be reviewed and submitted not less frequently than every 2 years".

There are three components to the L&RP: the Regional section, the State section, and the Merchant section. The Regional and State sections of the L&RP are developed from data collected from the FRCC Load and Resource Database (LRDB). Since Merchants within the FRCC do not have access to the LRDB portal, FRCC Staff collects information from Merchants through an Excel workbook survey.

The L&RP is reviewed by the FRCC Resource Subcommittee (RS), FRCC Transmission Technical Subcommittee (TTS), FRCC Load Forecasting Working Group (LFWG), and the FRCC LRDB users' group before it is finalized. FRCC Staff mails copies of the L&RP to the FPSC each year as well as members of certain FRCC committees, subcommittees, working groups, and user groups. The Plan is also posted to the FRCC website.

A high-level summary of information contained in each year's Plan is typically presented by the FRCC to the FPSC at its annual TYSP Workshop and may be expanded to include other items of interest to the Commission. The Workshop is usually scheduled in the fall of each year.

Annual reports that are compiled (in part or whole) from data extracted from the L&RP are the FRCC Load & Resource Reliability Assessment Report to the FPSC, and FRCC submissions to SERC including responses for the FL-Peninsula supporting NERC's Summer Assessment, Winter Assessment, and Long-Term Reliability Assessment. As new standards are developed, data extracted from the L&RP may be used to compile other reports to fulfill new requirements.

[1] Some exemptions apply. Refer to FPSC Rule 25-22.071 (Submission and Review of the Ten-Year Site Plans).

FLORIDA RELIABILITY COORDINATING COUNCIL
2025
REGIONAL LOAD & RESOURCE PLAN
INDEX

PAGE

I. DEMAND AND ENERGY

History and Forecast ... 6
History and Forecast of Energy Consumption and Number of Customers by Customer Class ... 7
History and Forecast of Summer Peak Demand (MW) ... 8
History and Forecast of Winter Peak Demand (MW) ... 9
History and Forecast of Annual Net Energy for Load (GWH) ... 10
Summary of Interruptible Load and Load Management (MW) ... 11

II. GENERATING FACILITIES

Summary of Existing Capacity ... 12
Existing Generating Facilities ... 13-26
Summary of Jointly Owned Generating Facilities ... 27-28
Planned and Prospective Generating Facility Additions and Change ... 29-39
Summary of Capacity, Demand, and Reserve Margin ... 40
Contracted Firm Imports and Firm Exports ... 41

III. NON-UTILITY GENERATORS

Existing Non-Utility, QF, and Self-Service Generation Facilities ... 42-46
Planned and Prospective Non-Utility, QF, and Self-Service Generation Facilities Installations, Changes, and Removals ... 47-49
Non-Utility Generating Facilities Summary ... 50

IV. CONTRACTS

Summary of Firm Capacity and Energy Contracts ... 51-57

V. FUELS

Fuel Requirements ... 58
Energy Sources (GWH) ... 59
Energy Sources (% of GWH) ... 60

VI. TRANSMISSION

Summary and Specifications of Proposed Transmission Lines ... 61

VII. GLOSSARY

Abbreviations of Electric Market Participants ... 61
Generation Terms ... 63
Contract Terms ... 64
Definitions ... 65

STATE SUPPLEMENT

MERCHANT DATA

FLORIDA RELIABILITY COORDINATING COUNCIL

2025

REGIONAL LOAD & RESOURCE PLAN

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND (MW)					WINTER PEAK DEMAND (MW)					ENERGY	
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2015	45,716				**2015 / 16**	37,881				**2015**	234,434	58.5%
2016	47,660				**2016 / 17**	36,309				**2016**	232,519	55.7%
2017	46,471				**2017 / 18**	42,877				**2017**	230,826	56.7%
2018	45,492				**2018 / 19**	36,008				**2018**	236,449	59.3%
2019	48,135				**2019 / 20**	38,357				**2019**	239,741	56.9%
2020	46,638				**2020 / 21**	37,171				**2020**	244,179	59.8%
2021	45,962				**2021 / 22**	40,920				**2021**	240,194	59.7%
2022	50,800				**2022 / 23**	41,899				**2022**	256,518	57.6%
2023	54,136				**2023 / 24**	38,392				**2023**	260,969	55.0%
2024	52,841				**2024 / 25**	45,084				**2024**	265,621	57.4%

YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2025	53,933	721	2,624	50,588	**2025 / 26**	48,628	699	2,428	45,501	**2025**	264,657	56.0%
2026	54,477	721	2,630	51,126	**2026 / 27**	49,209	699	2,436	46,074	**2026**	266,189	55.8%
2027	54,933	721	2,636	51,576	**2027 / 28**	49,875	699	2,435	46,741	**2027**	268,342	55.8%
2028	55,377	720	2,637	52,020	**2028 / 29**	50,763	699	2,433	47,631	**2028**	271,865	56.0%
2029	56,099	721	2,639	52,739	**2029 / 30**	51,487	699	2,438	48,350	**2029**	276,496	56.3%
2030	56,666	721	2,647	53,298	**2030 / 31**	52,096	699	2,444	48,953	**2030**	280,123	56.4%
2031	57,414	721	2,658	54,035	**2031 / 32**	52,809	699	2,448	49,662	**2031**	283,619	56.4%
2032	58,267	720	2,668	54,879	**2032 / 33**	53,537	699	2,455	50,383	**2032**	287,617	56.3%
2033	58,972	721	2,679	55,572	**2033 / 34**	54,232	699	2,458	51,075	**2033**	291,425	56.4%
2034	59,724	721	2,691	56,312	**2034 / 35**	54,931	699	2,465	51,767	**2034**	294,948	56.4%

NOTE: FORECASTED SUMMER AND WINTER DEMANDS ARE NON-COINCIDENT.

2025
LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 4.0
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL										
YEAR	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	STREET & HIGHWAY LIGHTING GWH	OTHER SALES GWH	TOTAL SALES GWH	WHOLESALE PURCHASES FOR RESALE GWH	WHOLESALE SALES FOR RESALE GWH	UTILITY USE & LOSSES GWH	AGGREGATION ADJUSTMENT GWH	NET ENERGY FOR LOAD GWH
2015	112,373	8,274,599	13,580	82,098	1,022,399	80,299	15,557	22,457	692,746	832	5,736	216,596	0	10,576	12,407	(5,145)	234,434
2016	113,305	8,400,713	13,488	82,399	1,037,365	79,431	15,418	22,907	673,069	823	5,718	217,663	0	11,033	10,789	(6,966)	232,519
2017	111,511	8,512,941	13,099	81,867	1,050,367	77,941	15,589	22,739	685,562	727	5,731	215,425	0	10,977	11,386	(6,962)	230,826
2018	114,461	8,602,399	13,306	82,198	1,055,794	77,854	15,396	22,479	684,906	722	5,932	218,709	0	11,317	11,648	(5,225)	236,449
2019	116,306	8,770,685	13,261	83,006	1,075,553	77,175	15,492	22,452	690,005	697	5,958	221,459	0	12,054	11,734	(5,506)	239,741
2020	122,096	8,923,839	13,682	79,500	1,087,846	73,080	15,406	22,231	692,996	682	5,733	223,417	0	13,161	11,786	(4,185)	244,179
2021	119,217	9,087,849	13,118	80,870	1,103,048	73,315	15,834	22,656	698,888	668	5,804	222,393	0	12,412	11,531	(6,142)	240,194
2022	128,131	9,671,978	13,248	87,137	1,178,083	73,965	17,897	24,045	744,313	700	5,987	239,852	0	14,421	11,351	(9,106)	256,518
2023	129,842	9,831,873	13,206	88,242	1,184,475	74,499	17,613	25,578	688,600	669	6,002	242,368	0	12,419	12,049	(5,867)	260,969
2024	132,086	10,056,332	13,135	89,514	1,202,198	74,459	17,787	25,131	707,771	686	5,950	246,023	0	12,409	12,944	(5,755)	265,621
2015-2024 % AAGR	**1.81%**			**0.97%**			**1.50%**										**1.40%**
2025	130,301	10,201,797	12,772	89,419	1,219,958	73,297	17,713	25,776	687,190	683	5,908	244,024	0	11,774	13,630	(4,771)	264,657
2026	131,373	10,356,887	12,685	90,201	1,236,577	72,944	18,028	25,795	698,895	644	5,907	246,153	0	11,900	13,236	(5,100)	266,189
2027	132,606	10,504,012	12,624	90,727	1,252,314	72,447	18,162	25,874	701,940	623	5,942	248,060	0	11,764	13,544	(5,026)	268,342
2028	134,172	10,650,579	12,598	91,441	1,267,518	72,142	19,573	26,029	751,969	614	5,951	251,751	0	11,227	13,947	(5,060)	271,865
2029	135,986	10,793,688	12,599	92,891	1,281,407	72,491	20,959	26,234	798,925	608	5,970	256,414	0	10,956	13,935	(4,809)	276,496
2030	137,836	10,934,672	12,605	93,923	1,296,969	72,417	22,391	26,421	847,470	608	5,984	260,742	0	10,120	14,110	(4,849)	280,123
2031	139,894	11,073,840	12,633	95,119	1,311,045	72,552	23,010	26,540	866,993	607	5,996	264,626	0	8,508	14,182	(3,697)	283,619
2032	142,097	11,211,021	12,675	95,740	1,324,883	72,263	23,609	26,563	888,793	608	5,985	268,039	0	8,529	14,798	(3,749)	287,617
2033	144,748	11,346,355	12,757	96,592	1,338,491	72,165	24,233	26,473	915,385	608	6,032	272,213	0	8,603	14,410	(3,801)	291,425
2034	147,179	11,479,407	12,821	97,278	1,351,856	71,959	24,310	26,291	924,651	609	6,039	275,415	0	8,676	14,711	(3,854)	294,948
2025-2034 % AAGR	**1.36%**			**0.94%**			**3.58%**										**1.21%**

NOTE: On January 1, 2019, Gulf Power Company (Gulf) became a subsidiary of NextEra Energy, Inc. which also owns FPL. In previous Load and Resource Plans before this integration occurred, Gulf's data was only shown within the State section of the report. The full consolidation of the two electric systems occurred in mid-2022 and the two systems began operating as a single, integrated utility system. All projected information presented for the years 2024 through 2034 is for the single integrated system (FPL), moving Gulf's capacity, demand, and energy into the FRCC section.

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 5.0
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	SUMMER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		SUMMER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2023	54,136	0	864	957	118	2,655	1,842	60,572
2024	52,841	0	926	984	187	2,685	1,860	59,483
2025	50,588	721	1,384	1,240	285	2,764	1,887	58,869
2026	51,126	721	1,380	1,250	340	2,824	1,908	59,549
2027	51,576	721	1,375	1,261	340	2,888	1,928	60,089
2028	52,020	720	1,368	1,269	340	2,950	1,949	60,616
2029	52,739	721	1,363	1,276	340	3,013	1,972	61,424
2030	53,298	721	1,363	1,284	340	3,075	1,994	62,075
2031	54,035	721	1,366	1,292	340	3,136	2,015	62,905
2032	54,879	720	1,367	1,301	340	3,196	2,035	63,838
2033	55,572	721	1,370	1,309	340	3,256	2,055	64,623
2034	56,312	721	1,372	1,319	340	3,317	2,074	65,455
CAAGR (%)	**1.20%**							

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 6.0
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	WINTER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		WINTER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2023/24	38,392	25	71	34	210	2,970	1,032	42,734
2024/25	45,084	285	66	127	402	2,999	1,046	50,009
2025/26	45,501	699	1,485	943	458	3,079	1,068	53,233
2026/27	46,074	699	1,484	952	459	3,144	1,083	53,895
2027/28	46,741	699	1,475	960	460	3,201	1,093	54,629
2028/29	47,631	699	1,466	967	461	3,277	1,109	55,610
2029/30	48,350	699	1,464	974	462	3,333	1,119	56,401
2030/31	48,953	699	1,463	981	462	3,403	1,135	57,096
2031/32	49,662	699	1,460	988	462	3,472	1,150	57,893
2032/33	50,383	699	1,459	996	463	3,519	1,160	58,679
2033/34	51,075	699	1,456	1,002	464	3,591	1,176	59,463
2034/35	51,767	699	1,456	1,009	465	3,668	1,192	60,256
CAAGR (%)	**1.44%**							

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 7.0
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWH)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
		ENERGY REDUCTION						
YEAR	NET ENERGY FOR LOAD	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	CUMULATIVE CONSERVATION RESIDENTIAL	CUMULATIVE CONSERVATION COMM./IND.	TOTAL ENERGY FOR LOAD
2023	260,969	0	0	0	1,352	6,120	4,923	273,364
2024	265,621	0	0	0	1,252	6,207	5,024	278,104
2025	264,657	0	0	11	1,488	6,370	5,126	277,653
2026	266,189	0	0	11	1,885	6,587	5,309	279,981
2027	268,342	0	0	11	1,885	6,858	5,542	282,638
2028	271,865	0	0	11	1,886	7,176	5,830	286,769
2029	276,496	0	0	11	1,885	7,540	6,174	292,107
2030	280,123	0	0	11	1,885	7,953	6,574	296,546
2031	283,619	0	0	11	1,885	8,414	7,031	300,960
2032	287,617	0	0	11	1,886	8,923	7,547	305,984
2033	291,425	0	0	11	1,885	9,481	8,120	310,923
2034	294,948	0	0	11	1,885	10,085	8,753	315,682
CAAGR (%)	**1.21%**							

2025

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF INTERRUPTIBLE LOAD AND LOAD MANAGEMENT (MW)

2025 THROUGH 2034

SUMMER

YEAR	DEF			FPL		JEA	SEC			TAL		TEC		FRCC TOTALS			FRCC TOTAL INT + LM
	INT	RES LM	COM LM	RES LM	COM LM	INT	INT	RES LM	COM LM	RES LM	COM LM	INT	COM LM	INT	RES LM	COM LM	
2025	415	380	94	937	1,025	105	66	67	11	0	0	135	110	721	1,384	1,240	3,345
2026	415	386	97	925	1,032	105	66	69	11	0	0	135	110	721	1,380	1,250	3,351
2027	415	392	101	913	1,038	105	66	70	11	0	0	135	111	721	1,375	1,261	3,357
2028	415	393	104	902	1,043	105	66	73	11	0	0	134	111	720	1,368	1,269	3,357
2029	415	394	107	896	1,047	105	66	73	11	0	0	135	111	721	1,363	1,276	3,360
2030	415	395	110	893	1,051	105	66	74	11	1	1	135	111	721	1,363	1,284	3,368
2031	415	396	113	891	1,055	105	66	76	11	3	1	135	112	721	1,366	1,292	3,379
2032	415	397	116	889	1,059	105	66	77	11	4	3	134	112	720	1,367	1,301	3,388
2033	415	398	119	888	1,063	105	66	79	11	5	4	135	112	721	1,370	1,309	3,400
2034	415	399	123	887	1,067	105	66	80	11	6	5	135	113	721	1,372	1,319	3,412

WINTER

YEAR	DEF			FPL		JEA	SEC			TAL		TEC		FRCC TOTALS			FRCC TOTAL INT + LM
	INT	RES LM	COM LM	RES LM	COM LM	INT	INT	RES LM	COM LM	RES LM	COM LM	INT	COM LM	INT	RES LM	COM LM	
2025/26	412	650	94	766	722	102	67	69	14	0	0	118	113	699	1,485	943	3,127
2026/27	412	658	97	754	727	102	67	72	14	0	0	118	114	699	1,484	952	3,135
2027/28	412	659	100	742	732	102	67	74	14	0	0	118	114	699	1,475	960	3,134
2028/29	412	660	103	731	735	102	67	75	14	0	0	118	115	699	1,466	967	3,132
2029/30	412	661	106	726	739	102	67	77	14	0	0	118	115	699	1,464	974	3,137
2030/31	412	662	109	721	742	102	67	80	14	0	0	118	116	699	1,463	981	3,143
2031/32	412	663	112	716	746	102	67	81	14	0	0	118	116	699	1,460	988	3,147
2032/33	412	664	116	712	749	102	67	83	14	0	0	118	117	699	1,459	996	3,154
2033/34	412	665	119	708	752	102	67	83	14	0	0	118	117	699	1,456	1,002	3,157
2034/35	412	666	122	705	755	102	67	85	14	0	0	118	118	699	1,456	1,009	3,164

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF EXISTING CAPACITY
AS OF DECEMBER 31, 2024

	NET CAPABILITY (MW)	
UTILITY	**SUMMER**	**WINTER**
DUKE ENERGY FLORIDA	10,463	10,673
FLORIDA MUNICIPAL POWER AGENCY	1,562	1,609
FLORIDA POWER & LIGHT COMPANY	31,687	29,874
GAINESVILLE REGIONAL UTILITIES	640	673
HOMESTEAD ENERGY SERVICES	32	32
JEA	2,782	2,952
KISSIMMEE UTILITY AUTHORITY	248	259
CITY OF LAKEWORTH BEACH	48	49
LAKELAND CITY OF	717	780
NEW SMYRNA BEACH UTILITIES COMMISSION OF	22	24
ORLANDO UTILITIES COMMISSION	1,380	1,417
TALLAHASSEE CITY OF	725	795
TAMPA ELECTRIC COMPANY	5,343	5,283
SEMINOLE ELECTRIC COOPERATIVE INC	2,992	3,162
US CORPS OF ENGINEERS - MOBILE	44	44
FRCC EXISTING CAPACITY (January 1)	58,684	57,624
FRCC EXISTING CAPACITY (Summer 25, Winter 25/26)	59,809	**60,116**
FIRM NON-UTILITY PURCHASES (January 1)	2,784	2,619
FIRM NON-UTILITY PURCHASES (Summer 25, Winter 25/26)	2,877	2,529
TOTAL FRCC EXISTING (January 1)	**61,468**	**60,243**
TOTAL FRCC EXISTING (Summer 25, Winter 25/26)	**62,686**	**62,645**

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
DUKE ENERGY FLORIDA															
ANCLOTE	2	PASCO	ST	NG	PL	NA	NA	0	10 / 1978	--- / ---	505	514	497	504	OP
ANCLOTE	1	PASCO	ST	NG	PL	NA	NA	0	10 / 1974	--- / ---	522	538	508	521	OP
BAYBORO	P3	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	10 / 2026	40	54	40	54	OP
BAYBORO	P1	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	10 / 2026	37	55	37	55	OP
BAYBORO	P2	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	10 / 2026	18.5	27.5	18.5	27.5	OP
BAYBORO	P4	PINELLAS	GT	DFO	WA	---	---	0	4 / 1973	10 / 2026	41	56	41	56	OP
CITRUS COMBINED CYCLE STATION	1GTA	CITRUS	CT	NG	PL	NA	NA	0	10 / 2018	--- / ---	244	296	243	295	OP
CITRUS COMBINED CYCLE STATION	1GTB	CITRUS	CT	NG	PL	NA	NA	0	10 / 2018	--- / ---	243	296	242	295	OP
CITRUS COMBINED CYCLE STATION	CC1ST	CITRUS	CA	WH	NA	NA	NA	0	10 / 2018	--- / ---	338	351	322	335	OP
CITRUS COMBINED CYCLE STATION	2GTA	CITRUS	CT	NG	PL	NA	NA	0	11 / 2018	--- / ---	246	297	245	296	OP
CITRUS COMBINED CYCLE STATION	2GTB	CITRUS	CT	NG	PL	NA	NA	0	11 / 2018	--- / ---	246	298	245	297	OP
CITRUS COMBINED CYCLE STATION	CC2ST	CITRUS	CA	WH	NA	NA	NA	0	11 / 2018	--- / ---	336	352	320	336	OP
CRYSTAL RIVER	4	CITRUS	ST	BIT	WA	BIT	RR	0	12 / 1982	6 / 2034	769	767	712	721	OP
CRYSTAL RIVER	5	CITRUS	ST	BIT	WA	BIT	RR	0	10 / 1984	6 / 2034	755	778	710	721	OP
DEBARY	P10	VOLUSIA	GT	DFO	TK	---	---	0	10 / 1992	--- / ---	72	88	72	88	OP
DEBARY	P7	VOLUSIA	GT	NG	PL	DFO	TK	8	10 / 1992	--- / ---	74	93	74	93	OP
DEBARY	P9	VOLUSIA	GT	NG	PL	DFO	TK	0	10 / 1992	--- / ---	76	94	76	94	OP
DEBARY	P6	VOLUSIA	GT	DFO	TK	---	---	0	4 / 1976	6 / 2027	46	59	46	59	OP
DEBARY	P3	VOLUSIA	GT	DFO	TK	---	---	0	12 / 1975	6 / 2027	45	59	45	59	OP
DEBARY	P5	VOLUSIA	GT	DFO	TK	---	---	0	12 / 1975	6 / 2027	45	58	45	58	OP
DEBARY	P4	VOLUSIA	GT	DFO	TK	---	---	0	4 / 1976	6 / 2027	46	59	46	59	OP
DEBARY	P2	VOLUSIA	GT	DFO	TK	---	---	0	3 / 1976	6 / 2027	45	57	45	57	OP
DEBARY	P8	VOLUSIA	GT	NG	PL	DFO	TK	0	10 / 1992	--- / ---	75	94	75	94	OP
HINES ENERGY COMPLEX	4GT1	POLK	CT	NG	PL	DFO	TK	0	12 / 2007	--- / ---	189	180	188	179	OP
HINES ENERGY COMPLEX	1ST	POLK	CA	WH	NA	DFO	TK	0	4 / 1999	--- / ---	172	175	167	170	OP
HINES ENERGY COMPLEX	2GT1	POLK	CT	NG	PL	DFO	TK	0	12 / 2003	--- / ---	177	180	176	179	OP
HINES ENERGY COMPLEX	2GT2	POLK	CT	NG	PL	DFO	TK	0	12 / 2003	--- / ---	175	184	174	183	OP
HINES ENERGY COMPLEX	2ST	POLK	CA	WH	NA	NA	NA	0	12 / 2003	--- / ---	188	193	182	187	OP
HINES ENERGY COMPLEX	4GT2	POLK	CT	NG	PL	DFO	TK	0	12 / 2007	--- / ---	177	180	176	179	OP
HINES ENERGY COMPLEX	4ST	POLK	CA	WH	NA	DFO	TK	0	12 / 2007	--- / ---	186	192	180	186	OP
HINES ENERGY COMPLEX	1GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 1999	--- / ---	168	175	167	174	OP
HINES ENERGY COMPLEX	1GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 1999	--- / ---	168	178	167	177	OP
HINES ENERGY COMPLEX	3GT1	POLK	CT	NG	PL	DFO	TK	0	11 / 2005	--- / ---	172	176	171	175	OP
HINES ENERGY COMPLEX	3GT2	POLK	CT	NG	PL	DFO	TK	0	11 / 2005	--- / ---	177	178	176	177	OP
HINES ENERGY COMPLEX	3ST	POLK	CA	WH	NA	NA	NA	0	11 / 2005	--- / ---	182	189	176	183	OP
INTERCESSION CITY	P12	OSCEOLA	GT	NG	PL	DFO	PL	5	12 / 2000	--- / ---	73	89	73	89	OP
INTERCESSION CITY	P3	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	46	61	46	61	OP
INTERCESSION CITY (*)	P11	OSCEOLA	GT	DFO	PL	NA	NA	0	1 / 1997	--- / ---	140	161	140	161	OP
INTERCESSION CITY	P4	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	46	62	46	62	OP
INTERCESSION CITY	P8	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / ---	77	88	77	88	OP
INTERCESSION CITY	P7	OSCEOLA	GT	NG	PL	DFO	PL	5	10 / 1993	--- / ---	78	90	78	90	OP
INTERCESSION CITY	P9	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / ---	77	88	77	88	OP
INTERCESSION CITY	P10	OSCEOLA	GT	NG	PL	DFO	PL	0	10 / 1993	--- / ---	74	86	74	86	OP
INTERCESSION CITY	P13	OSCEOLA	GT	NG	PL	DFO	PL	0	12 / 2000	--- / ---	73	91	73	91	OP
INTERCESSION CITY	P14	OSCEOLA	GT	NG	PL	DFO	PL	0	12 / 2000	--- / ---	73	90	73	90	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
INTERCESSION CITY	P5	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	45	59	45	59	OP
INTERCESSION CITY	P6	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	47	60	47	60	OP
INTERCESSION CITY	P1	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	45	61	45	61	OP
INTERCESSION CITY	P2	OSCEOLA	GT	DFO	PL	---	---	0	5 / 1974	6 / 2034	46	60	46	60	OP
Osprey Energy Center	GT1	POLK	CT	NG	PL	DFO	TK	2	5 / 2004	--- / ---	81.6	81.6	81.6	81.6	OP
Osprey Energy Center	GT2	POLK	CT	NG	PL	DFO	TK	2	5 / 2004	--- / ---	81.6	81.6	81.6	81.6	OP
Osprey Energy Center	ST1	POLK	ST	NG	PL	DFO	TK	2	5 / 2004	--- / ---	81.8	81.8	81.8	81.8	OP
P. L. BARTOW	P2	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 1972	6 / 2034	41	53	41	53	OP
P. L. BARTOW	P4	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 1972	6 / 2034	45	58	45	58	OP
P. L. BARTOW	4AGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / ---	191	217	190	205.9	OP
P. L. BARTOW	4BGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / ---	174	215	173	203.9	OP
P. L. BARTOW	P3	PINELLAS	GT	DFO	WA	---	---	0	6 / 1972	6 / 2027	41	51	41	51	OP
P. L. BARTOW	P1	PINELLAS	GT	DFO	WA	---	---	0	5 / 1972	6 / 2027	41	50	41	50	OP
P. L. BARTOW	4CGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / ---	194	198	193	187.8	OP
P. L. BARTOW	4DGT	PINELLAS	CT	NG	PL	DFO	TK	0	6 / 2009	--- / ---	177	204	176	193.5	OP
P. L. BARTOW	4ST	PINELLAS	CA	WH	NA	DFO	TK	0	6 / 2009	--- / ---	426	445	410	408.9	OP
SUWANNEE RIVER	P2	SUWANNEE	GT	NG	PL	DFO	TK	0	10 / 1980	6 / 2034	48	64	48	64	OP
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	PL	DFO	TK	0	11 / 1980	6 / 2034	49	65	49	65	OP
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	PL	DFO	TK	9	10 / 1980	6 / 2034	48	65	48	65	OP
TIGER BAY	1GT	POLK	CT	NG	PL	---	---	0	8 / 1997	--- / ---	130	160	130	160	OP
TIGER BAY	1ST	POLK	CA	WH	NA	---	---	0	8 / 1997	--- / ---	72	73	69	70	OP
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	NG	PL	NA	---	0	1 / 1994	--- / ---	45	51	44	50	OP
											DEF TOTAL:		**9,688**	**10,601**	
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION INC															
MARATHON	9	MONROE	IC	DFO	TK	RFO	TK	0	1 / 2001	--- / ---	3.5	3.5	3.5	3.5	SB
MARATHON	8	MONROE	IC	DFO	TK	RFO	TK	0	1 / 1998	--- / ---	3.5	3.5	3.5	3.5	SB
MARATHON	1	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1988	--- / ---	2	2	2	2	SB
MARATHON	2	MONROE	IC	DFO	TK	RFO	TK	0	6 / 1988	--- / ---	2	2	2	2	SB
											FKE TOTAL:		-	-	
FLORIDA MUNICIPAL POWER AGENCY															
CANE ISLAND (*)	1GT	OSCEOLA	GT	NG	PL	DFO	TK	0	11 / 1994	--- / ---	17.5	19	17.5	19	OP
CANE ISLAND (*)	2CT	OSCEOLA	CT	NG	PL	---	---	0	6 / 1995	--- / ---	35.5	37.5	34.5	36.5	OP
CANE ISLAND (*)	2CW	OSCEOLA	CA	WH	NA	---	---	0	6 / 1995	--- / ---	22	22	20	20	OP
CANE ISLAND (*)	3CW	OSCEOLA	CA	WH	NA	NA	NA	0	1 / 2002	--- / ---	49.4	50.3	46.9	47.8	OP
CANE ISLAND (*)	3CT	OSCEOLA	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	80.1	84.2	78.1	82.2	OP
CANE ISLAND	4CT	OSCEOLA	CT	NG	PL	---	---	0	7 / 2011	--- / ---	154	159	150	155	OP
CANE ISLAND	4CW	OSCEOLA	CA	WH	NA	---	---	0	7 / 2011	--- / ---	153	158	150	155	OP
INDIAN RIVER	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	14.2	18	12.2	14.1	OP
INDIAN RIVER (*)	D	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	22.3	26.2	21.6	23	OP
INDIAN RIVER	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	14.2	18	12.2	14.1	OP
INDIAN RIVER (*)	C	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	22.3	26.2	21.6	23	OP
Mulberry	1CT	POLK	CT	NG	PL	NA	NA	0	8 / 2024	--- / ---	73.4	78.2	73.4	78.2	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
Mulberry	1CW	POLK	CA	WH	NA	NA	NA	0	8 / 2024	--- / ---	34.6	36.8	34.6	36.8	OP
Sand Lake Energy Center	1	ORANGE	CS	NG	PL	WH	NA	0	2 / 2024	--- / ---	120	120	120	120	OP
ST. LUCIE (*)	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / ---	86.2	89.6	86.2	89.6	OP
STANTON (*)	1	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	12 / 2025	118.5	118.5	118.5	118.5	OP
STANTON (*)	2	ORANGE	ST	BIT	RR	---	---	0	6 / 1996	--- / ---	129.9	129.9	129.8	129.8	OP
STANTON A (*)	CT	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ---	11.6	13.1	11.6	13.1	OP
STANTON A (*)	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / ---	10.3	10.4	10.3	10.4	OP
STOCK ISLAND	CT2	MONROE	GT	DFO	TK	---	---	0	9 / 1999	--- / ---	15.9	15.9	15.9	15.9	OP
STOCK ISLAND	CT3	MONROE	GT	DFO	TK	---	---	0	9 / 1999	--- / ---	14.1	14.1	14.1	14.1	OP
STOCK ISLAND	CT4	MONROE	GT	DFO	TK	---	---	0	6 / 2006	--- / ---	46	46	46	46	OP
STOCK ISLAND	EP2	MONROE	IC	DFO	TK	---	---	0	7 / 2014	--- / ---	2	2	2	2	OP
STOCK ISLAND	GT1	MONROE	GT	DFO	TK	---	---	0	11 / 1978	--- / ---	19.8	19.8	18.5	18.5	OP
STOCK ISLAND MSD	MSD1	MONROE	IC	DFO	TK	---	---	0	6 / 1991	--- / ---	8.8	8.8	8	8	OP
STOCK ISLAND MSD	MSD2	MONROE	IC	DFO	TK	---	---	0	6 / 1991	--- / ---	8.8	8.8	8	8	OP
TREASURE COAST ENERGY CTR	1	ST. LUCIE	CT	NG	PL	DFO	TK	0	6 / 2008	--- / ---	154	159	150	155	OP
TREASURE COAST ENERGY CTR	1	ST. LUCIE	CA	WH	NA	DFO	TK	0	6 / 2008	--- / ---	153	158	150	155	OP
											FMPA TOTAL:		**1,562**	**1,609**	
FLORIDA POWER & LIGHT COMPANY															
CAPE CANAVERAL	3A	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / ---	270.4	307.8	270.4	307.8	OP
CAPE CANAVERAL	3ST	BREVARD	ST	NG	PL	DFO	TK	4	4 / 2013	--- / ---	478.8	494.6	478.8	494.6	OP
CAPE CANAVERAL	3B	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / ---	270.4	307.8	270.4	307.8	OP
CAPE CANAVERAL	3C	BREVARD	CT	NG	PL	DFO	TK	4	4 / 2013	--- / ---	270.4	307.8	270.4	307.8	OP
DANIA BEACH CLEAN ENERGY CENTER	7CTA	BROWARD	CT	NG	PL	DFO	TK	0	1 / 2022	--- / ---	434.1	441.2	434.1	441.2	OP
DANIA BEACH CLEAN ENERGY CENTER	7CTB	BROWARD	CT	NG	PL	DFO	TK	0	1 / 2022	--- / ---	434.1	441.2	434.1	441.2	OP
DANIA BEACH CLEAN ENERGY CENTER	7ST	BROWARD	ST	NG	PL	DFO	TK	0	1 / 2022	--- / ---	377.8	369.6	377.8	369.6	OP
ECHO RIVER BATTERY STORAGE	1	SUWANNEE	BA	BS	NA	NA	NA	0	12 / 2021	--- / ---	30	30	30	30	OP
FT. MYERS	9	LEE	GT	DFO	WA	---	---	0	5 / 1974	--- / ---	51	61.5	51	61.5	OP
FT. MYERS	3CTC	LEE	CT	NG	TK	DFO	NA	7	12 / 2016	--- / ---	231	229	231	229	OP
FT. MYERS	3CTD	LEE	CT	NG	TK	DFO	NA	7	12 / 2016	--- / ---	231	229	231	229	OP
FT. MYERS	1	LEE	GT	DFO	WA	---	---	0	5 / 1974	--- / ---	51	61.5	51	61.5	OP
FT. MYERS	2CTA	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2CTB	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2CTC	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2CTD	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2CTE	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2CTF	LEE	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	219.4	203.2	219.4	OP
FT. MYERS	2ST1	LEE	CA	WH	NA	---	---	0	6 / 2002	--- / ---	139	144.9	139	144.9	OP
FT. MYERS	2ST2	LEE	CA	WH	NA	---	---	0	6 / 2002	--- / ---	463.8	458.7	463.8	458.7	OP
FT. MYERS	3CTA	LEE	CT	NG	PL	DFO	TK	7	6 / 2001	--- / ---	195	205	195	205	OP
FT. MYERS	3CTB	LEE	CT	NG	PL	DFO	TK	7	6 / 2001	--- / ---	195	205	195	205	OP
GULF CLEAN ENERGY CENTER	5	ESCAMBIA	ST	NG	PL	NA	NA	0	1 / 2022	12 / 2029	75	75	75	75	OP
GULF CLEAN ENERGY CENTER	6	ESCAMBIA	ST	NG	PL	NA	NA	0	1 / 2022	--- / ---	315	315	315	315	OP
GULF CLEAN ENERGY CENTER	7	ESCAMBIA	ST	NG	PL	NA	NA	0	1 / 2022	--- / ---	496	496	496	496	OP
GULF CLEAN ENERGY CENTER	8CTA	ESCAMBIA	CT	NG	PL	NA	NA	0	12 / 2021	--- / ---	234	238	234	238	OP
GULF CLEAN ENERGY CENTER	8CTB	ESCAMBIA	CT	NG	PL	NA	NA	0	12 / 2021	--- / ---	234	238	234	238	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
GULF CLEAN ENERGY CENTER	8CTC	ESCAMBIA	CT	NG	PL	NA	NA	0	12 / 2021	--- / ---	229	232	229	232	OP
GULF CLEAN ENERGY CENTER	8CTD	ESCAMBIA	CT	NG	PL	NA	NA	0	12 / 2021	--- / ---	229	232	229	232	OP
GULF CLEAN ENERGY CENTER	4	ESCAMBIA	ST	NG	PL	NA	NA	0	1 / 2022	--- / ---	75	75	75	75	OP
LANSING SMITH	3	BAY	CC	NG	PL	NA	NA	0	4 / 2022	--- / ---	641	665	641	665	OP
LANSING SMITH	A	BAY	GT	DFO	TK	NA	NA	0	1 / 2022	12 / 2027	32	40	32	40	OP
LAUDERDALE	5	BROWARD	GT	NG	PL	DFO	TK	3	8 / 1970	--- / ---	34.3	36.7	34.3	36.7	OP
LAUDERDALE	6CTA	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ---	231	229	231	229	OP
LAUDERDALE	6CTB	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ---	231	229	231	229	OP
LAUDERDALE	6CTC	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ---	231	229	231	229	OP
LAUDERDALE	6CTD	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ---	231	229	231	229	OP
LAUDERDALE	6CTE	BROWARD	CT	NG	PL	DFO	TK	2	12 / 2016	--- / ---	231	229	231	229	OP
LAUDERDALE	3	BROWARD	GT	NG	PL	DFO	TK	3	8 / 1970	--- / ---	34.3	36.7	34.3	36.7	OP
MANATEE	3CTA	MANATEE	CT	NG	PL	NA	NA	0	6 / 2005	--- / ---	192.9	217.7	192.9	217.7	OP
MANATEE	3CTB	MANATEE	CT	NG	PL	NA	NA	0	6 / 2005	--- / ---	192.9	217.7	192.9	217.7	OP
MANATEE	3CTC	MANATEE	CT	NG	PL	NA	NA	0	6 / 2005	--- / ---	192.9	217.7	192.9	217.7	OP
MANATEE	3CTD	MANATEE	CT	NG	PL	NA	NA	0	6 / 2005	--- / ---	192.9	217.7	192.9	217.7	OP
MANATEE	3ST	MANATEE	CA	NG	PL	NA	NA	0	6 / 2005	--- / ---	474.2	475.4	474.2	475.4	OP
MANATEE	1	MANATEE	ST	NG	PL	RFO	WA	21	10 / 1976	12 / 2034	0	819	0	819	OS
MANATEE	2	MANATEE	ST	NG	PL	RFO	WA	21	12 / 1977	12 / 2034	0	819	0	819	OS
MANATEE BATTERY STORAGE	1	MANATEE	BA	BS	NA	NA	NA	0	12 / 2021	--- / ---	409	409	409	409	OP
MARTIN	3ST	MARTIN	CA	NG	PL	---	---	0	2 / 1994	--- / ---	157	158.8	157	158.8	OP
MARTIN	3GT1	MARTIN	CT	NG	PL	---	---	0	2 / 1994	--- / ---	165	189.6	165	189.6	OP
MARTIN	4GT1	MARTIN	CT	NG	PL	DFO	TK	0	4 / 1994	--- / ---	165	185.1	165	185.1	OP
MARTIN	4GT2	MARTIN	CT	NG	PL	---	---	0	4 / 1994	--- / ---	165	185.1	165	185.1	OP
MARTIN	8CTA	MARTIN	CT	NG	PL	DFO	NA	0	6 / 2005	--- / ---	198.7	217.9	198.7	217.9	OP
MARTIN	8CTB	MARTIN	CT	NG	PL	DFO	NA	0	6 / 2005	--- / ---	198.7	217.9	198.7	217.9	OP
MARTIN	8CTC	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ---	198.7	217.9	198.7	217.9	OP
MARTIN	8CTD	MARTIN	CT	NG	PL	DFO	TK	3	6 / 2005	--- / ---	198.7	217.9	198.7	217.9	OP
MARTIN	8ST	MARTIN	CA	NG	PL	DFO	TK	0	6 / 2005	--- / ---	454.2	455.6	454.2	455.6	OP
MARTIN	3GT2	MARTIN	CT	NG	PL	---	---	0	2 / 1994	--- / ---	165	189.6	165	189.6	OP
MARTIN	4ST	MARTIN	CA	NG	PL	---	---	0	4 / 1994	--- / ---	157	158.8	157	158.8	OP
OKEECHOBEE	1A	OKEECHOBEE	CT	NG	PL	DFO	TK	3	3 / 2019	--- / ---	396.3	387	396.3	387	OP
OKEECHOBEE	1B	OKEECHOBEE	CT	NG	PL	DFO	TK	3	3 / 2019	--- / ---	396.3	387	396.3	387	OP
OKEECHOBEE	1C	OKEECHOBEE	CT	NG	PL	DFO	TK	3	3 / 2019	--- / ---	396.3	387	396.3	387	OP
OKEECHOBEE	1ST	OKEECHOBEE	CA	NG	PL	DFO	TK	3	3 / 2019	--- / ---	531.1	511	531.1	511	OP
PEA RIDGE	1	SANTA ROSA	GT	NG	PL	NA	NA	0	1 / 2022	4 / 2025	4	5	4	5	OP
PEA RIDGE	2	SANTA ROSA	GT	NG	PL	NA	NA	0	1 / 2022	4 / 2025	4	5	4	5	OP
PEA RIDGE	3	SANTA ROSA	GT	NG	PL	NA	NA	0	1 / 2022	4 / 2025	4	5	4	5	OP
PERDIDO	1	ESCAMBIA	IC	LFG	PL	NA	NA	0	1 / 2022	12 / 2029	1.5	1.5	1.5	1.5	OP
PERDIDO	2	ESCAMBIA	IC	LFG	PL	NA	NA	0	1 / 2022	12 / 2029	1.5	1.5	1.5	1.5	OP
PORT EVERGLADES	5A	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / ---	271.9	295.4	271.9	295.4	OP
PORT EVERGLADES	5B	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / ---	271.9	295.4	271.9	295.4	OP
PORT EVERGLADES	5C	BROWARD	CT	NG	PL	DFO	TK	5	4 / 2016	--- / ---	271.9	295.4	271.9	295.4	OP
PORT EVERGLADES	5ST	BROWARD	CA	NG	PL	DFO	TK	5	4 / 2016	--- / ---	421.3	446.8	421.3	446.8	OP
RIVIERA	5A	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / ---	270.4	298.2	270.4	298.2	OP
RIVIERA	5B	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / ---	270.4	298.2	270.4	298.2	OP
RIVIERA	5C	PALM BEACH	CT	NG	PL	DFO	TK	4	6 / 2014	--- / ---	270.4	298.2	270.4	298.2	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
RIVIERA	5ST	PALM BEACH	CA	NG	PL	DFO	TK	4	6 / 2014	--- / ---	478.8	511.3	478.8	511.3	OP
SANFORD	4CTA	VOLUSIA	CT	NG	PL	NA	NA	0	10 / 2003	--- / ---	203.2	220.4	203.2	220.4	OP
SANFORD	4CTB	VOLUSIA	CT	NG	PL	NA	NA	0	10 / 2003	--- / ---	203.2	220.4	203.2	220.4	OP
SANFORD	4CTC	VOLUSIA	CT	NG	PL	NA	NA	0	10 / 2003	--- / ---	203.2	220.4	203.2	220.4	OP
SANFORD	4CTD	VOLUSIA	CT	NG	PL	NA	NA	0	10 / 2003	--- / ---	203.2	220.4	203.2	220.4	OP
SANFORD	5CTA	VOLUSIA	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	213.9	203.2	213.9	OP
SANFORD	5CTB	VOLUSIA	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	213.9	203.2	213.9	OP
SANFORD	5CTC	VOLUSIA	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	213.9	203.2	213.9	OP
SANFORD	5CTD	VOLUSIA	CT	NG	PL	NA	NA	0	6 / 2002	--- / ---	203.2	213.9	203.2	213.9	OP
SANFORD	4ST	VOLUSIA	CA	NG	PL	NA	NA	0	10 / 2003	--- / ---	396.2	396.4	396.2	396.4	OP
SANFORD	5ST	VOLUSIA	CA	NG	PL	NA	NA	0	6 / 2002	--- / ---	396.2	396.4	396.2	396.4	OP
SCHERER (*)	3	MONROE GA	ST	BIT	RR	NA	NA	0	1 / 2022	12 / 2034	215	215	215	215	OP
ST. LUCIE (*)	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / ---	843	862	840	860	OP
ST. LUCIE	1	ST. LUCIE	ST	NUC	TK	---	---	0	5 / 1976	--- / ---	1032	1072	981	1003	OP
SUNSHINE GATEWAY BATTERY STORAGE	1	COLUMBIA	BA	BS	NA	NA	NA	0	12 / 2021	--- / ---	30	30	30	30	OP
TURKEY POINT	3	DADE	ST	NUC	TK	NA	NA	0	12 / 1972	--- / ---	837	859	837	859	OP
TURKEY POINT	4	DADE	ST	NUC	TK	NA	NA	0	9 / 1973	--- / ---	844	866	844	866	OP
TURKEY POINT	5ST	DADE	CA	NG	PL	DFO	TK	3	5 / 2007	--- / ---	487.2	486	487.2	486	OP
TURKEY POINT	5CTA	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / ---	201.2	218	201.2	218	OP
TURKEY POINT	5CTB	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / ---	201.2	218	201.2	218	OP
TURKEY POINT	5CTC	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / ---	201.2	218	201.2	218	OP
TURKEY POINT	5CTD	DADE	CT	NG	PL	DFO	TK	3	5 / 2007	--- / ---	201.2	218	201.2	218	OP
TURKEY POINT	2	DADE	ST	RFO	WA	NG	PL	0	4 / 1968	--- / ---	0	0	0	0	OS
TURKEY POINT	1	DADE	ST	RFO	WA	NG	PL	0	4 / 1967	--- / ---	0	0	0	0	OS
WEST COUNTY	CT1B	PALM BEACH	CT	NG	PL	DFO	TK	0	8 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	CT1C	PALM BEACH	CT	NG	PL	DFO	TK	2	8 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	ST1	PALM BEACH	CA	NG	PL	DFO	TK	2	8 / 2009	--- / ---	493.5	495.2	493.5	495.2	OP
WEST COUNTY	ST2	PALM BEACH	CA	NG	PL	DFO	TK	2	11 / 2009	--- / ---	493.5	495.2	493.5	495.2	OP
WEST COUNTY	CT2A	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	CT2B	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	CT2C	PALM BEACH	CT	NG	PL	DFO	TK	2	11 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	CT1A	PALM BEACH	CT	NG	PL	DFO	TK	2	8 / 2009	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	3GT2	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	3GT1	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / ---	254.5	284.6	254.5	284.6	OP
WEST COUNTY	3ST	PALM BEACH	CA	NG	PL	DFO	TK	2	6 / 2011	--- / ---	493.5	495.2	493.5	495.2	OP
WEST COUNTY	3GT3	PALM BEACH	CT	NG	PL	DFO	TK	2	6 / 2011	--- / ---	254.5	284.6	254.5	284.6	OP
											FPL TOTAL:		**28,493**	**29,782**	
GAINESVILLE REGIONAL UTILITIES															
DEERHAVEN	FS01	ALACHUA	ST	NG	PL	RFO	TK	0	8 / 1972	12 / 2027	81	81	76	76	OP
DEERHAVEN	GT01	ALACHUA	GT	NG	PL	DFO	TK	0	7 / 1976	12 / 2031	18	23	17.5	22	OP
DEERHAVEN	GT03	ALACHUA	GT	NG	PL	DFO	TK	0	1 / 1996	--- / ---	71.5	82	71	81	OP
DEERHAVEN	FS02	ALACHUA	ST	NG	PL	BIT	RR	0	10 / 1981	12 / 2036	251	251	232	232	OP
DEERHAVEN	GT02	ALACHUA	GT	NG	PL	DFO	TK	0	8 / 1976	12 / 2031	18	23	17.5	22	OP
DEERHAVEN RENEWABLE	1	ALACHUA	ST	WDS	TK	NA	NA	0	12 / 2013	--- / ---	114	114	103	103	OP
J. R. KELLY	FS08	ALACHUA	CA	WH	NA	NA	NA	0	5 / 2001	--- / ---	41.5	41.5	41	41	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
J. R. KELLY	GT04	ALACHUA	CT	NG	PL	DFO	TK	0	5 / 2001	--- / ---	72.5	85.9	71	84.4	OP
SOUTH ENERGY CENTER	1	ALACHUA	GT	NG	PL	NA	NA	0	5 / 2009	--- / ---	4.5	4.5	3.8	4.1	OP
SOUTH ENERGY CENTER	2	ALACHUA	IC	NG	PL	NA	NA	0	12 / 2017	--- / ---	7.4	7.4	7.4	7.4	OP
											GRU TOTAL:		**640**	**673**	
HOMESTEAD ENERGY SERVICES															
G. W. IVEY	3	DADE	IC	NG	PL	DFO	TK	100	3 / 1970	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	14	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	21	DADE	IC	NG	PL	DFO	TK	100	5 / 1981	--- / ---	6.5	6.5	6	6	OP
G. W. IVEY	13	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	2	DADE	IC	NG	PL	DFO	TK	100	3 / 1970	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	15	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	16	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	19	DADE	IC	NG	PL	DFO	TK	100	2 / 1975	--- / ---	9	9	7.5	7.5	OP
G. W. IVEY	17	DADE	IC	NG	PL	DFO	TK	100	11 / 1972	--- / ---	2	2	1.8	1.8	OP
G. W. IVEY	20	DADE	IC	NG	PL	DFO	TK	100	5 / 1981	--- / ---	6.5	6.5	6	6	OP
											HST TOTAL:		**32**	**32**	
JEA															
BRANDY BRANCH	CT2	DUVAL	CT	NG	PL	NA	NA	0	5 / 2001	--- / ---	190.5	212.2	189.7	211.7	OP
BRANDY BRANCH	CT3	DUVAL	CT	NG	PL	NA	NA	0	10 / 2001	--- / ---	190.5	212.2	189.7	211.7	OP
BRANDY BRANCH	STM4	DUVAL	CA	WH	NA	NA	NA	0	1 / 2005	--- / ---	210	225	200	216.1	OP
BRANDY BRANCH	GT1	DUVAL	GT	NG	PL	DFO	TK	8	5 / 2001	--- / ---	180.1	192.7	178.6	191.2	OP
GREENLAND ENERGY CTR	GT1	DUVAL	GT	NG	PL	DFO	TK	2	6 / 2011	--- / ---	180.1	192.7	178.6	191.2	OP
GREENLAND ENERGY CTR	GT2	DUVAL	GT	NG	PL	DFO	TK	2	6 / 2011	--- / ---	180.1	192.7	178.6	191.2	OP
J. D. KENNEDY	GT8	DUVAL	GT	NG	PL	DFO	WA	4	6 / 2009	--- / ---	180.1	192.7	178.6	191.2	OP
J. D. KENNEDY	GT7	DUVAL	GT	NG	PL	DFO	WA	4	6 / 2000	--- / ---	180.1	192.7	178.6	191.2	OP
NORTHSIDE	GT4	DUVAL	GT	DFO	WA	---	---	0	1 / 1975	--- / ---	50.4	62	50	61.6	OP
NORTHSIDE	GT6	DUVAL	GT	DFO	WA	---	---	0	12 / 1974	--- / ---	50.4	62	50	61.6	OP
NORTHSIDE	2	DUVAL	ST	PC	WA	BIT	WA	0	4 / 2003	--- / ---	310	310	293	293	OP
NORTHSIDE	1	DUVAL	ST	PC	WA	BIT	WA	0	5 / 2003	--- / ---	310	310	293	293	OP
NORTHSIDE	GT3	DUVAL	GT	DFO	WA	---	---	0	1 / 1975	--- / ---	50.4	62	50	61.6	OP
NORTHSIDE	3	DUVAL	ST	NG	PL	RFO	WA	9	6 / 1977	12 / 2030	540	540	524	524	OP
NORTHSIDE	GT5	DUVAL	GT	DFO	WA	---	---	0	12 / 1974	--- / ---	50.4	62	50	61.6	OP
											JEA TOTAL:		**2,782**	**2,952**	
KISSIMMEE UTILITY AUTHORITY															
CANE ISLAND (*)	3CW	OSCEOLA	CA	WH	NA	NA	NA	0	1 / 2002	--- / ---	49.3	50.3	46.8	47.8	OP
CANE ISLAND (*)	2CT	OSCEOLA	CT	NG	PL	---	---	0	6 / 1995	--- / ---	35.5	37.5	34.5	36.5	OP
CANE ISLAND (*)	2CW	OSCEOLA	CA	WH	NA	---	---	0	6 / 1995	--- / ---	22	22	20	20	OP
CANE ISLAND (*)	1GT	OSCEOLA	GT	NG	PL	DFO	TK	0	1 / 1995	--- / ---	17.5	19	17.5	19	OP
CANE ISLAND (*)	3CT	OSCEOLA	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	80.1	84.1	78.1	82.1	OP
INDIAN RIVER (*)	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	4.4	5.6	3.8	4.4	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
INDIAN RIVER (*)	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	4.4	5.6	3.8	4.4	OP
STANTON (*)	1	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	12 / 2025	22	22	21.5	21.5	OP
STANTON A (*)	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / ---	10.3	10.4	10.3	10.4	OP
STANTON A (*)	CT	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ---	11.6	13.1	11.6	13.1	OP
											KUA TOTAL:		**248**	**259**	
LAKELAND CITY OF															
LARSEN	3	POLK	GT	NG	PL	DFO	TK	0	12 / 1962	--- / ---	9	13	9	13	OS
LARSEN	8ST	POLK	CA	WH	NA	NA	NA	0	4 / 1956	--- / ---	30	30	29.7	29.7	OP
LARSEN	8CT	POLK	CT	NG	PL	DFO	TK	0	7 / 1992	--- / ---	85	95	84.7	94.7	OP
LARSEN	2	POLK	GT	NG	PL	DFO	TK	0	11 / 1962	--- / ---	10	14	10	14	OS
MCINTOSH	GT2	POLK	CT	NG	PL	DFO	TK	0	6 / 2020	--- / ---	120	125	119.5	124.5	OP
MCINTOSH	MREP 4-6	POLK	IC	NG	PL	NA	NA	0	12 / 2024	--- / ---	60	60	59.5	59.5	OP
MCINTOSH	5ST	POLK	CA	WH	NA	NA	NA	0	5 / 2002	--- / ---	125	125	118	118	OP
MCINTOSH	D1	POLK	IC	DFO	TK	NA	NA	0	1 / 1970	--- / ---	2.5	2.5	2.5	2.5	OP
MCINTOSH	D2	POLK	IC	DFO	TK	NA	NA	0	1 / 1970	--- / ---	2.5	2.5	2.5	2.5	OP
MCINTOSH	GT1	POLK	GT	NG	PL	DFO	TK	0	5 / 1973	--- / ---	17	19	17	19	OP
MCINTOSH	5CT	POLK	CT	NG	PL	NA	NA	0	5 / 2001	--- / ---	234	280	234	280	OP
WINSTON	11-15	POLK	IC	DFO	TK	NA	NA	0	12 / 2001	--- / ---	12.5	12.5	12.5	12.5	OP
WINSTON	1-5	POLK	IC	DFO	TK	NA	NA	0	12 / 2001	--- / ---	12.5	12.5	12.5	12.5	OP
WINSTON	6-10	POLK	IC	DFO	TK	NA	NA	0	12 / 2001	--- / ---	12.5	12.5	12.5	12.5	OP
WINSTON	16-20	POLK	IC	DFO	TK	NA	NA	0	12 / 2001	--- / ---	12.5	12.5	12.5	12.5	OP
											LAK TOTAL:		**717**	**780**	
CITY OF LAKEWORTH BEACH															
TOM G. SMITH	GT-1	PALM BEACH	GT	DFO	TK	---	---	0	12 / 1976	--- / ---	26	29	26	27	OP
TOM G. SMITH	MU4	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / ---	2	2	1.8	2	IR
TOM G. SMITH	GT-2	PALM BEACH	CT	NG	PL	DFO	TK	2	3 / 1978	--- / ---	21	23	20	20	OP
TOM G. SMITH	MU1	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / ---	2	2	1.8	2	IR
TOM G. SMITH	MU3	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / ---	2	2	1.8	2	IR
TOM G. SMITH	MU5	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / ---	2	2	1.8	2	IR
TOM G. SMITH	S-5	PALM BEACH	CA	WH	NA	---	---	0	3 / 1978	4 / 2025	0	0	0	0	IR
TOM G. SMITH	S-3	PALM BEACH	ST	NG	PL	---	---	0	11 / 1967	4 / 2025	0	0	0	0	IR
TOM G. SMITH	MU2	PALM BEACH	IC	DFO	TK	---	---	0	12 / 1965	--- / ---	2	2	1.8	2	IR
											LWBU TOTAL:		**46**	**47**	
NEW SMYRNA BEACH UTILITIES COMMISSION OF															
FIELD STREET	1	VOLUSIA	GT	DFO	TK	---	---	0	5 / 2001	--- / ---	22	24	22	24	OP
FIELD STREET	2	VOLUSIA	GT	DFO	TK	---	---	0	5 / 2001	--- / ---	22	24	22	24	OS
											NSB TOTAL:		**22**	**24**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
ORLANDO UTILITIES COMMISSION															
INDIAN RIVER (*)	A	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	15.6	18.1	15.6	18.1	OP
INDIAN RIVER (*)	C	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	83	88.5	83	88.5	OP
INDIAN RIVER (*)	D	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	83	88.5	83	88.5	OP
INDIAN RIVER (*)	B	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	15.6	18.1	15.6	18.1	OP
OSCEOLA GENERATING STATION	1	OSCEOLA	GT	NG	PL	DFO	TK	3	12 / 2001	--- / ---	157	157	157	157	OS
OSCEOLA GENERATING STATION	2	OSCEOLA	GT	NG	PL	DFO	TK	3	12 / 2001	--- / ---	197.2	197.2	157	157	OS
OSCEOLA GENERATING STATION	3	OSCEOLA	GT	NG	PL	DFO	TK	3	6 / 2002	--- / ---	157	157	157	157	OS
ST. LUCIE (*)	2	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / ---	63	63	60	62	OP
STANTON (*)	1	ORANGE	ST	BIT	RR	NA	NA	0	7 / 1987	--- / ---	321	321	310.6	310.6	OP
STANTON (*)	2	ORANGE	ST	BIT	RR	NA	NA	0	6 / 1996	--- / ---	344	344	335.8	335.8	OP
STANTON A (*)	CTA	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ---	60.5	60.5	56.6	56.4	OP
STANTON A (*)	CTB	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ---	60.5	60.5	56.6	56.4	OP
STANTON A (*)	ST	ORANGE	CA	WH	PL	DFO	TK	3	10 / 2003	--- / ---	76.7	81.6	71	75.6	OP
STANTON B	CT	ORANGE	CT	NG	PL	DFO	TK	3	2 / 2010	--- / ---	173	185	170	182	OP
STANTON B	ST	ORANGE	CA	WH	NA	DFO	TK	3	2 / 2010	--- / ---	122	125	122	125	OP
											OUC TOTAL:		**1,380**	**1,417**	
SEMINOLE ELECTRIC COOPERATIVE INC															
MIDULLA GENERATING STATION	ST	HARDEE	CA	WH	NA	DFO	TK	13	1 / 2002	--- / ---	188	190	186	188	OP
MIDULLA GENERATING STATION	CT2	HARDEE	CT	NG	PL	DFO	TK	13	1 / 2002	--- / ---	171	208	169	206	OP
MIDULLA GENERATING STATION	CT1	HARDEE	CT	NG	PL	DFO	TK	13	1 / 2002	--- / ---	171	208	169	206	OP
MIDULLA GENERATING STATION	4	HARDEE	GT	NG	PL	DFO	TK	13	12 / 2006	--- / ---	54	62	54	62	OP
MIDULLA GENERATING STATION	5	HARDEE	GT	NG	PL	DFO	TK	13	12 / 2006	--- / ---	54	62	54	62	OP
MIDULLA GENERATING STATION	7	HARDEE	GT	NG	PL	DFO	TK	13	12 / 2006	--- / ---	54	62	54	62	OP
MIDULLA GENERATING STATION	6	HARDEE	GT	NG	PL	DFO	TK	13	12 / 2006	--- / ---	54	62	54	62	OP
MIDULLA GENERATING STATION	8	HARDEE	GT	NG	PL	DFO	TK	13	12 / 2006	--- / ---	27	31	27	31	OP
SEMINOLE CC FACILITY	CTG1	PUTNAM	CT	NG	PL	NA	NA	0	4 / 2023	--- / ---	358.6	372.8	352.6	367	OP
SEMINOLE CC FACILITY	CTG2	PUTNAM	CT	NG	PL	NA	NA	0	4 / 2023	--- / ---	360.6	374.8	354.6	369	OP
SEMINOLE CC FACILITY	STG3	PUTNAM	CA	WH	NA	NA	NA	0	4 / 2023	--- / ---	400.6	388.8	393.5	381.9	OP
SEMINOLE GENERATING STATION	2	PUTNAM	ST	BIT	RR	NA	NA	0	12 / 1984	--- / ---	680	688	634	640	OP
Shady Hill Generating Station	1	PASCO	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	164	176	163	175	OP
Shady Hill Generating Station	2	PASCO	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	164	176	163	175	OP
Shady Hill Generating Station	3	PASCO	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	164	176	163	175	OP
											SEC TOTAL:		**2,991**	**3,162**	
TALLAHASSEE CITY OF															
HOPKINS	GT3	LEON	GT	NG	PL	DFO	TK	3	9 / 2005	--- / ---	49	49	46	48	OP
HOPKINS	2A	LEON	CT	NG	PL	DFO	TK	3	6 / 2008	--- / ---	160	186	159	185	OP
HOPKINS	GT4	LEON	GT	NG	PL	DFO	TK	3	11 / 2005	--- / ---	49	49	46	48	OP
HOPKINS	2	LEON	CA	WH	NA	NG	PL	0	10 / 1977	--- / ---	146	150	141	145	OP
HOPKINS	IC 1	LEON	IC	NG	PL	NA	NA	0	3 / 2019	--- / ---	18.8	18.8	18.5	18.5	OP
HOPKINS	IC 2	LEON	IC	NG	PL	NA	NA	0	2 / 2019	--- / ---	18.8	18.8	18.5	18.5	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
HOPKINS	IC 4	LEON	IC	NG	PL	NA	NA	0	2 / 2019	--- / ---	18.8	18.8	18.5	18.5	OP
HOPKINS	IC 5	LEON	IC	NG	PL	NA	NA	0	4 / 2020	--- / ---	18.8	18.8	18.5	18.5	OP
PURDOM	8ST	WAKULLA	CA	WH	NA	NA	NA	0	7 / 2000	--- / ---	76.3	80.8	72	76	OP
PURDOM	8CT	WAKULLA	CT	NG	PL	DFO	TK	9	7 / 2000	--- / ---	160.7	185.2	150	182	OP
Substation 12	IC 1	LEON	IC	NG	PL	NA	NA	0	10 / 2018	--- / ---	9.3	9.3	9.2	9.2	OP
Substation 12	IC 2	LEON	IC	NG	PL	NA	NA	0	10 / 2018	--- / ---	9.3	9.3	9.2	9.2	OP
											TAL TOTAL:		**706**	**776**	
TAMPA ELECTRIC COMPANY															
BAYSIDE	3	HILLSBOROUGH	GT	NG	PL	NA	NA	0	7 / 2009	--- / ---	57	62	56	61	OP
BAYSIDE	4	HILLSBOROUGH	GT	NG	PL	NA	NA	0	7 / 2009	--- / ---	57	62	56	61	OP
BAYSIDE	6	HILLSBOROUGH	GT	NG	PL	NA	NA	0	4 / 2009	--- / ---	57	62	56	61	OP
BAYSIDE	5	HILLSBOROUGH	GT	NG	PL	NA	NA	0	4 / 2009	--- / ---	57	62	56	61	OP
BAYSIDE	2A	HILLSBOROUGH	CT	NG	PL	NA	NA	0	1 / 2004	--- / ---	170	198	168	196	OP
BAYSIDE	2D	HILLSBOROUGH	CT	NG	PL	NA	NA	0	1 / 2004	--- / ---	170	198	168	196	OP
BAYSIDE	1C	HILLSBOROUGH	CT	NG	PL	NA	NA	0	4 / 2003	--- / ---	170	198	168	196	OP
BAYSIDE	1ST	HILLSBOROUGH	CA	WH	NA	NA	NA	0	4 / 2003	--- / ---	248	262	245	259	OP
BAYSIDE	1A	HILLSBOROUGH	CT	NG	PL	NA	NA	0	4 / 2003	--- / ---	170	198	168	196	OP
BAYSIDE	1B	HILLSBOROUGH	CT	NG	PL	NA	NA	0	4 / 2003	--- / ---	170	198	168	196	OP
BAYSIDE	2B	HILLSBOROUGH	CT	NG	PL	NA	NA	0	1 / 2004	--- / ---	170	198	168	196	OP
BAYSIDE	2C	HILLSBOROUGH	CT	NG	PL	NA	NA	0	1 / 2004	--- / ---	170	198	168	196	OP
BAYSIDE	2ST	HILLSBOROUGH	CA	WH	NA	NA	NA	0	1 / 2004	--- / ---	330	340	329	337	OP
BIG BEND	1	HILLSBOROUGH	ST	WH	WA	NA	NA	0	10 / 1970	--- / ---	350	351	335	336	OP
BIG BEND	CT4	HILLSBOROUGH	GT	NG	PL	---	---	0	8 / 2009	--- / ---	57	62	56	61	OP
BIG BEND	4	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	2 / 1985	--- / ---	455	465	437	442	OP
BIG BEND	CT5	HILLSBOROUGH	GT	NG	PL	---	---	0	12 / 2021	--- / ---	370	397	360	392	OP
BIG BEND	CT6	HILLSBOROUGH	GT	NG	PL	---	---	0	12 / 2021	--- / ---	370	397	360	392	OP
BIG BEND BATTERY STORAGE	BESS1	HILLSBOROUGH	BA	NA	NA	NA	NA	0	12 / 2019	--- / ---	12.6	12.6	12.6	12.6	OP
DOVER BATTERY STORAGE	BESS1	HILLSBOROUGH	BA	NA	NA	NA	NA	0	12 / 2024	--- / ---	15	15	15	15	OP
POLK	2 St	POLK	CA	WH	NA	NA	NA	0	1 / 2017	--- / ---	479	499	461	480	OP
POLK	1CA	POLK	CA	WH	NA	NA	NA	0	9 / 1996	--- / ---	120	120	51	51	OP
POLK	2	POLK	CT	NG	PL	DFO	TK	3	7 / 2000	--- / ---	151	181	150	180	OP
POLK	5	POLK	CT	NG	PL	NA	NA	0	4 / 2007	--- / ---	151	181	150	180	OP
POLK	4	POLK	CT	NG	PL	NA	NA	0	3 / 2007	--- / ---	151	181	150	180	OP
POLK	3	POLK	CT	NG	PL	DFO	TK	3	5 / 2002	--- / ---	151	181	150	180	OP
POLK	1CT	POLK	CT	PC	TK	NG	PL	0	9 / 1996	--- / ---	170	170	169	169	OP
											TEC TOTAL:		**4,831**	**5,283**	
US CORPS OF ENGINEERS - MOBILE															
JIM WOODRUFF	2	GADSDEN	HY	WAT	NA	NA	NA	0	3 / 1957	--- / ---	14.5	14.5	14.5	14.5	OP
JIM WOODRUFF	3	GADSDEN	HY	WAT	NA	NA	NA	0	4 / 1957	--- / ---	14.5	14.5	14.5	14.5	OP
JIM WOODRUFF	1	GADSDEN	HY	WAT	NA	NA	NA	0	2 / 1957	--- / ---	14.5	14.5	14.5	14.5	OP
											UCEM TOTAL:		**44**	**44**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
TOTAL FRCC EXISTING (Exisiting Firm solar):													54,181	57,440	
FRCC EXISTING SOLAR:													4,485	166	
TOTAL FRCC EXISTING:													58,666	57,606	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0 - Solar
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-SERVICE	EXPECTED RETIREMENT	NAMEPLATE CAPABILITY$_{AC}$	NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	MO. / YEAR	MO. / YEAR	(MW)	SUMMER (MW)	WINTER (MW)	STATUS
DUKE ENERGY FLORIDA														
BAY RANCH SOLAR POWER PLANT	PV1	BAY	PV	SUN	NA	NA	NA	0	4 / 2023	--- / ---	74.9	40	4	OP
BAY TRAIL SOLAR POWER PLANT	PV1	CITRUS	PV	SUN	NA	NA	NA	0	11 / 2022	--- / ---	74.9	40	4	OP
CHARLIE CREEK SOLAR POWER PLANT	PV1	HARDEE	PV	SUN	NA	NA	NA	0	8 / 2022	--- / ---	74.9	40	4	OP
Columbia Solar Power Plant	PV1	COLUMBIA	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.9	39.3	3.6	OP
COUNTY LINE RENEWABLE ENERGY CEN	PV1	GILCHRIST	PV	SUN	NA	NA	NA	0	8 / 2024	--- / ---	74.9	40.2	3.8	OP
DeBary Solar Power Plant	PV1	VOLUSIA	PV	SUN	NA	NA	NA	0	5 / 2020	--- / ---	74.5	39	3.6	OP
DUETTE SOLAR POWER PLANT	PV1	MANATEE	PV	SUN	NA	NA	NA	0	10 / 2021	--- / ---	74.5	39.4	3.6	OP
FALMOUTH RENEWABLE ENERGY CENTE	PV1	SUWANNEE	PV	SUN	NA	NA	NA	0	6 / 2024	--- / ---	74.9	40	3.8	OP
FORT GREEN SOLAR POWER PLANT	PV1	HARDEE	PV	SUN	NA	NA	NA	0	6 / 2022	--- / ---	74.9	39.6	3.7	OP
HAMILTON SOLAR POWER PLANT	PV1	HAMILTON	PV	SUN	NA	NA	NA	0	12 / 2018	--- / ---	74.9	39.1	3.5	OP
HARDEETOWN SOLAR POWER PLANT	PV1	LEVY	PV	SUN	NA	NA	NA	0	4 / 2023	--- / ---	74.9	39.9	3.8	OP
HIGH SPRINGS SOLAR POWER PLANT	PV1	ALACHUA	PV	SUN	NA	NA	NA	0	4 / 2023	--- / ---	74.9	39.9	3.8	OP
HILDRETH SOLAR POWER PLANT	PV1	SUWANNEE	PV	SUN	NA	NA	NA	0	4 / 2023	--- / ---	74.9	39.9	3.8	OP
Lake Placid Solar Power Plant	PV1	HIGHLANDS	PV	SUN	NA	NA	NA	0	12 / 2019	--- / ---	45	13.5	1.2	OP
MULE CREEK RENEWABLE ENERGY CEN	PV1	BAY	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.9	40	3.8	OP
OSCEOLA SOLAR	PV1	OSCEOLA	PV	SUN	NA	NA	NA	0	5 / 2016	--- / ---	3.8	2	0.2	OP
PERRY SOLAR	PV1	TAYLOR	PV	SUN	NA	NA	NA	0	8 / 2016	--- / ---	5.1	2.6	0.2	OP
SANDY CREEK SOLAR POWER PLANT	PV1	BAY	PV	SUN	NA	NA	NA	0	5 / 2022	--- / ---	74.9	39.6	3.7	OP
SANTA FE SOLAR POWER PLANT	PV1	COLUMBIA	PV	SUN	NA	NA	NA	0	3 / 2021	--- / ---	74.9	39.4	3.7	OP
SUWANNEE RIVER	PV1	SUWANNEE	PV	SUN	NA	NA	NA	0	11 / 2017	--- / ---	8.8	4.5	0.4	OP
Trenton Solar Power Plant	PV1	GILCHRIST	PV	SUN	NA	NA	NA	0	12 / 2019	--- / ---	74.9	39.2	3.6	OP
TWIN RIVERS SOLAR POWER PLANT	PV1	HAMILTON	PV	SUN	NA	NA	NA	0	3 / 2021	--- / ---	74.9	39.4	3.7	OP
WINQUEPIN RENEWABLE ENERGY CENTI	PV1	MADISON	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.9	40	3.8	OP
											DEF TOTAL:	**776**	**73**	
FLORIDA POWER & LIGHT COMPANY														
ANHINGA SOLAR	1	CLAY	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	28.4	1.8	OP
APALACHEE SOLAR	1	JACKSON	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	36	0	OP
BABCOCK PRESERVE SOLAR	1	CHARLOTTE	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	37.2	0	OP
BABCOCK RANCH SOLAR	1	CHARLOTTE	PV	SUN	UN	NA	NA	0	12 / 2016	--- / ---	74.5	37.3	0	OP
BAREFOOT BAY SOLAR	1	BREVARD	PV	SUN	NA	NA	NA	0	3 / 2018	--- / ---	74.5	41.4	0	OP
BEAUTYBERRY SOLAR	1	SANTA ROSA	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	30	2.5	OP
BIG JUNIPER SOLAR	1	SANTA ROSA	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	36.7	0	OP
BLACKWATER RIVER SOLAR	1	SANTA ROSA	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	27.8	0	OP
BLUE CYPRESS SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	3 / 2018	--- / ---	74.5	39.7	0	OP
BLUE HERON SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	37.5	0	OP
BLUE INDIGO SOLAR	1	JACKSON	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	49.9	0	OP
Blue Springs Solar	1	JACKSON	PV	SUN	NA	NA	NA	0	12 / 2021	--- / ---	74.5	41	0	OP
BLUEFIELD PRESERVE SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	75.5	21.9	1.9	OP
BUTTONWOOD	1	ST LUCIE	PV	SUN	NA	NA	NA	0	11 / 2024	--- / ---	74.5	33.6	2.2	OP
CALOOSAHATCHEE SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	29.6	1.9	OP
CANOE SOLAR	1	OKALOOSA	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	37.1	0	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0 - Solar
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-SERVICE	EXPECTED RETIREMENT	NAMEPLATE CAPABILITY$_{AC}$	NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	MO. / YEAR	MO. / YEAR	(MW)	SUMMER (MW)	WINTER (MW)	STATUS
CATTLE RANCH SOLAR	1	DESOTO	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	28.6	1.5	OP
CAVENDISH SOLAR	1	OKEECHOBEE	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	29.7	4.2	OP
CEDAR TRAIL SOLAR	1	BAKER	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	5.6	0.2	OP
CHAUTAUQUA SOLAR	1	WALTON	PV	SUN	NA	NA	NA	0	2 / 2023	--- / ---	74.5	40.1	0	OP
CHIPOLA SOLAR	1	CALHOUN	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	33.8	0	OP
CITRUS SOLAR	1	DESOTO	PV	SUN	UN	NA	NA	0	12 / 2016	--- / ---	74.5	38.8	0	OP
CORAL FARMS SOLAR	1	PUTNAM	PV	SUN	NA	NA	NA	0	1 / 2018	--- / ---	74.5	46.5	11	OP
Cotton Creek Solar	1	JACKSON	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	41.1	0	OP
CYPRESS POND SOLAR	1	WASHINGTON	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	37.1	0	OP
DESOTO NEXT GENERATION SOLAR ENE	1	DESOTO	PV	SUN	UN	NA	NA	0	10 / 2009	--- / ---	23	10.2	0.7	OP
DISCOVERY SOLAR	1	BREVARD	PV	SUN	NA	NA	NA	0	7 / 2021	--- / ---	74.5	36.9	0.9	OP
ECHO RIVER SOLAR	1	SUWANNEE	PV	SUN	NA	NA	NA	0	5 / 2020	--- / ---	30	42.6	0	OP
EGRET SOLAR	1	BAKER	PV	SUN	NA	NA	NA	0	12 / 2020	--- / ---	74.5	38.1	0.2	OP
ELDER BRANCH SOLAR	1	BAKER	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	32.1	0.5	OP
ETONIA CREEK SOLAR	1	PUTNAM	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	34.3	1.3	OP
EVERGLADES SOLAR	1	DADE	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	23.9	3.1	OP
FIRST CITY SOLAR	1	ESCAMBIA	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	28.6	0	OP
FLOWERS CREEK SOLAR	1	CALHOUN	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	34.2	0	OP
FORT DRUM SOLAR	1	OKEECHOBEE	PV	SUN	NA	NA	NA	0	8 / 2021	--- / ---	74.5	34.8	0.9	OP
FOURMILE CREEK SOLAR	1	CALHOUN	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	38.5	0	OP
GEORGES LAKES SOLAR	1	PUTNAM	PV	SUN	NA	NA	NA	0	11 / 2024	--- / ---	74.5	5	0.6	OP
GHOST ORCHID SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	22	1.9	OP
GROVE SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	24.2	1.8	OP
HAMMOCK SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	3 / 2018	--- / ---	74.5	38.9	0	OP
HAWTHORNE CREEK SOLAR	1	DESOTO	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	31.4	1.1	OP
HENDRY ISLES SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	11 / 2024	--- / ---	74.5	22.1	2.3	OP
HIBISCUS SOLAR	1	PALM BEACH	PV	SUN	NA	NA	NA	0	5 / 2020	--- / ---	74.5	36.7	0	OP
HONEYBELL SOLAR	1	OKEECHOBEE	PV	SUN	NA	NA	NA	0	11 / 2024	--- / ---	74.5	32.8	2.2	OP
HORIZON SOLAR	1	PUTNAM	PV	SUN	NA	NA	NA	0	1 / 2018	--- / ---	74.5	39.2	1.1	OP
IBIS SOLAR	1	BREVARD	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	35	1.9	OP
IMMOKALEE SOLAR	1	COLLIER	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	20.7	2.4	OP
INDIAN RIVER SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	1 / 2018	--- / ---	74.5	39.5	0	OP
INTERSTATE SOLAR	1	ST LUCIE	PV	SUN	UN	NA	NA	0	1 / 2019	--- / ---	74.5	37.9	0	OP
KAYAK SOLAR	1	OKALOOSA	PV	SUN	NA	NA	NA	0	12 / 2024	--- / ---	74.5	10.9	0	OP
LAKESIDE SOLAR	1	OKEECHOBEE	PV	SUN	NA	NA	NA	0	12 / 2020	--- / ---	74.5	36	1.1	OP
LOGGERHEAD SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	1 / 2018	--- / ---	74.5	26.3	0.5	OP
MAGNOLIA SPRINGS SOLAR	1	CLAY	PV	SUN	NA	NA	NA	0	4 / 2021	--- / ---	74.5	39.1	1	OP
MANATEE SOLAR	1	MANATEE	PV	SUN	UN	NA	NA	0	12 / 2016	--- / ---	74.5	38.7	0	OP
MIAMI DADE SOLAR	1	DADE	PV	SUN	UN	NA	NA	0	1 / 2019	--- / ---	74.5	36.1	0	OP
MITCHELL CREEK SOLAR	1	ESCAMBIA	PV	SUN	NA	NA	NA	0	11 / 2024	--- / ---	74.5	29.1	0	OP
MONARCH SOLAR	1	MARTIN	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	30.3	1.5	OP
NASSAU SOLAR	1	NASSAU	PV	SUN	NA	NA	NA	0	12 / 2020	--- / ---	74.5	37	1	OP
NATURE TRAIL SOLAR	1	BAKER	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	37.6	0.3	OP
NORTHERN PRESERVE SOLAR	1	BAKER	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	33.6	0	OP
NORTON CREEK SOLAR	1	MADISON	PV	SUN	NA	NA	NA	0	12 / 2024	--- / ---	74.5	24.2	0	OP

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0 - Solar
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-	EXPECTED	NAMEPLATE	NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	CAPABILITY$_{AC}$ (MW)	SUMMER (MW)	WINTER (MW)	STATUS
OKEECHOBEE SOLAR	1	OKEECHOBEE	PV	SUN	NA	NA	NA	0	3 / 2019	--- / ---	74.5	36.2	0	OP
ORANGE BLOSSOM SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	7 / 2021	--- / ---	74.5	37.8	1.2	OP
ORCHARD SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	35.9	2.9	OP
PALM BAY SOLAR	1	BREVARD	PV	SUN	NA	NA	NA	0	5 / 2021	--- / ---	74.5	39.7	0.8	OP
PECAN TREE SOLAR	1	WALTON	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.9	40	0	OP
PELICAN SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	4 / 2021	--- / ---	74.5	37.6	1.8	OP
PINEAPPLE SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	32.6	2.1	OP
PINK TRAIL SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	21.8	2.5	OP
PIONEER TRAIL SOLAR	1	VOLUSIA	PV	SUN	UN	NA	NA	0	1 / 2019	--- / ---	74.5	35.6	0	OP
PRAIRIE CREEK SOLAR	1	DESOTO	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	32	1.3	OP
RODEO SOLAR	1	DESOTO	PV	SUN	NA	NA	NA	0	5 / 2021	--- / ---	74.5	36.6	1.5	OP
SABAL PALM SOLAR	1	PALM BEACH	PV	SUN	NA	NA	NA	0	6 / 2021	--- / ---	74.5	38.2	1.5	OP
SAMBUCUS SOLAR	1	MANATEE	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	30.7	0.9	OP
SAW PALMETTO SOLAR	1	BAY	PV	SUN	NA	NA	NA	0	1 / 2023	--- / ---	74.5	39.7	0	OP
SAWGRASS SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	21.8	1.9	OP
SHIRER BRANCH SOLAR	1	CALHOUN	PV	SUN	NA	NA	NA	0	2 / 2023	--- / ---	74.5	39.4	0	OP
SILVER PALM SOLAR	1	PALM BEACH	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	30.9	2.6	OP
SOUTHFORK SOLAR	1	MANATEE	PV	SUN	NA	NA	NA	0	5 / 2020	--- / ---	74.5	43.1	0	OP
SPACE COAST	1	BREVARD	PV	SUN	UN	NA	NA	0	4 / 2010	--- / ---	10	3.7	0.1	OP
SPARKLEBERRY SOLAR	1	ESCAMBIA	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	37.9	0	OP
SUNDEW SOLAR	1	ST LUCIE	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	74.5	26.3	1.9	OP
SUNSHINE GATEWAY SOLAR	1	COLUMBIA	PV	SUN	UN	NA	NA	0	1 / 2019	--- / ---	74.5	40.3	0	OP
SWEETBAY SOLAR	1	MARTIN	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	31.1	0	OP
TERRILL CREEK SOLAR	1	CLAY	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	34.2	0.6	OP
THREE CREEKS SOLAR	1	MANATEE	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	32.9	0.9	OP
TRAILSIDE SOLAR	1	ST JOHNS	PV	SUN	NA	NA	NA	0	12 / 2020	--- / ---	74.5	39.5	1	OP
TURNPIKE SOLAR	1	INDIAN RIVER	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	34.6	2.8	OP
TWIN LAKES SOLAR	1	PUTNAM	PV	SUN	NA	NA	NA	0	3 / 2020	--- / ---	74.5	38.3	0.9	OP
UNION SPRINGS SOLAR	1	UNION	PV	SUN	NA	NA	NA	0	12 / 2020	--- / ---	74.5	38.9	0.8	OP
WHITE TAIL SOLAR	1	MARTIN	PV	SUN	NA	NA	NA	0	1 / 2024	--- / ---	74.5	36.3	3.1	OP
WILD AZALEA SOLAR	1	GADSDEN	PV	SUN	NA	NA	NA	0	2 / 2023	--- / ---	74.5	40.9	0	OP
WILD QUAIL SOLAR	1	WALTON	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	41.3	0	OP
WILDFLOWER SOLAR	1	DESOTO	PV	SUN	NA	NA	NA	0	1 / 2018	--- / ---	74.5	38.6	0	OP
WILLOW SOLAR	1	MANATEE	PV	SUN	NA	NA	NA	0	7 / 2021	--- / ---	74.5	35.8	1.3	OP
WOODYARD SOLAR	1	HENDRY	PV	SUN	NA	NA	NA	0	3 / 2024	--- / ---	74.5	28.9	2.1	OP
											FPL TOTAL:	**3,194**	**92**	
CITY OF LAKEWORTH BEACH														
TOM G. SMITH	PV-1	PALM BEACH	PV	SUN	NA	NA	NA	0	8 / 2017	--- / ---	1.7	1.7	1.7	OP
											LWBU TOTAL:	**2**	**2**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.0 - Solar
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)	(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COM'L IN-SERVICE	EXPECTED RETIREMENT	NAMEPLATE CAPABILITY$_{AC}$	NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	MO. / YEAR	MO. / YEAR	(MW)	SUMMER (MW)	WINTER (MW)	STATUS
SEMINOLE ELECTRIC COOPERATIVE INC														
MGS Solar	1	HARDEE	PV	SUN	NA	NA	NA	0	8 / 2017	--- / ---	2.2	0.9	0	OP
											SEC TOTAL:	**1**	**-**	
TAMPA ELECTRIC COMPANY														
ALAFIA SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	12 / 2023	--- / ---	60	15.2	0	OP
BALM SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	9 / 2018	--- / ---	74.4	41.2	0	OP
BIG BEND AGRIVOLTAIC	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	6 / 2022	--- / ---	1	0.2	0	OP
BIG BEND FLOATING SOLAR 1	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	3 / 2022	--- / ---	1	0.2	0	OP
BIG BEND II SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	1 / 2022	--- / ---	45.8	11.6	0	OP
BIG BEND SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	2 / 2017	--- / ---	19.8	14.1	0	OP
BONNIE MINE SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	1 / 2019	--- / ---	37.5	17.8	0	OP
BULLFROG CREEK SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2024	--- / ---	74.5	3.7	0	OP
DOVER SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2023	--- / ---	25	6.3	0	OP
DURRANCE SOLAR	1	POLK	PV	SUN	NA	NA	---	0	1 / 2021	--- / ---	60	34.4	0	OP
ENGLISH CREEK SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2024	--- / ---	23	1.2	0	OP
GRANGE HALL SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	1 / 2019	--- / ---	61.1	33.4	0	OP
JAMISON SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	4 / 2022	--- / ---	74.5	18.8	0	OP
JUNIPER SOLAR	1	PASCO	PV	SUN	NA	NA	NA	0	12 / 2023	--- / ---	70	17.8	0	OP
LAKE HANCOCK SOLAR	1	POLK	PV	SUN	NA	---	---	0	4 / 2019	--- / ---	49.5	26.1	0	OP
LAKE MABEL SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	12 / 2023	--- / ---	74.5	18.9	0	OP
LAUREL OAKS SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2022	--- / ---	61.2	15.5	0	OP
LEGOLAND SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	12 / 2016	--- / ---	1.4	0.5	0	OP
LITHIA SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	1 / 2019	--- / ---	74.5	37.7	0	OP
LITTLE MANATEE RIVER SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	2 / 2020	--- / ---	74.5	37.9	0	OP
MAGNOLIA SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	12 / 2021	--- / ---	74.5	18.8	0	OP
MOUNTAIN VIEW SOLAR	1	PASCO	PV	SUN	NA	NA	NA	0	4 / 2022	--- / ---	54.6	13.8	0	OP
PAYNE CREEK SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	9 / 2018	--- / ---	70.3	39.9	0	OP
PEACE CREEK SOLAR	1	POLK	PV	SUN	NA	NA	NA	0	3 / 2019	--- / ---	55.4	30.5	0	OP
RIVERSIDE SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2022	--- / ---	55.2	13.9	0	OP
TIA SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	12 / 2015	--- / ---	1.6	0.7	0	OP
WIMAUMA SOLAR	1	HILLSBOROUGH	PV	SUN	NA	NA	NA	0	4 / 2020	--- / ---	74.8	42	0	OP
											TEC TOTAL:	**512**	**-**	
											TOTAL FRCC EXISTING (Excluding Firm solar):	**54,181**	**57,440**	
											FRCC EXISTING SOLAR:	**4,485**	**166**	
											TOTAL FRCC EXISTING:	**58,666**	**57,606**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 2.0
SUMMARY OF JOINTLY OWNED GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	NET CAPABILITY		
PLANT NAME	UTILS	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	STATUS
CANE ISLAND 1	FMPA	OSCEOLA	GT	NG	PL	DFO	TK	0	11 / 1994	--- / ---	17.5	19	OP
	KUA										17.5	19	OP
											35	**38**	
CANE ISLAND 2	FMPA	OSCEOLA	CT	NG	PL	---	---	0	6 / 1995	--- / ---	54.5	56.5	OP
	KUA										54.5	56.5	OP
											109	**113**	
CANE ISLAND 3	FMPA	OSCEOLA	CT	NG	PL	NA	NA	0	1 / 2002	--- / ---	125	130	OP
	KUA										124.9	129.9	OP
											249.9	**259.9**	
INDIAN RIVER A	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	12.2	14.1	OP
	KUA										3.8	4.4	OP
	OUC										15.6	18.1	OP
											31.6	**36.6**	
INDIAN RIVER B	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	7 / 1989	--- / ---	12.2	14.1	OP
	KUA										3.8	4.4	OP
	OUC										15.6	18.1	OP
											31.6	**36.6**	
INDIAN RIVER C	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	21.6	23	OP
	OUC										83	88.5	OP
											104.6	**111.5**	
INDIAN RIVER D	FMPA	BREVARD	GT	NG	PL	DFO	TK	0	8 / 1992	--- / ---	21.6	23	OP
	OUC										83	88.5	OP
											104.6	**111.5**	
SCHERER 3	FPL	MONROE GA	ST	BIT	RR	NA	NA	0	1 / 2022	--- / ---	**215**	**215**	OP
ST. LUCIE 2	FMPA	ST. LUCIE	ST	NUC	TK	---	---	0	6 / 1983	--- / ---	86.2	89.6	OP
	FPL										840	860	OP
	OUC										60	62	OP
											986.2	**1011.6**	
STANTON 1	FMPA	ORANGE	ST	BIT	RR	---	---	0	7 / 1987	--- / ---	118.5	118.5	OP
	KUA										21.5	21.5	OP
	OUC										310.6	310.6	OP
											450.6	**450.6**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 2.0

SUMMARY OF JOINTLY OWNED GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE	COMMERCIAL	EXPECTED	NET CAPABILITY		
PLANT NAME	UTILS	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	(DAYS BURN)	IN-SERVICE MO. / YEAR	RETIREMENT MO. / YEAR	SUMMER (MW)	WINTER (MW)	STATUS
STANTON 2	FMPA	ORANGE	ST	BIT	RR	---	---	0	6 / 1996	--- / ---	129.8	129.8	OP
	OUC										335.8	335.8	OP
											465.6	**465.6**	
STANTON A	FMPA	ORANGE	CT	NG	PL	DFO	TK	3	10 / 2003	--- / ---	21.9	23.5	OP
	KUA										21.9	23.5	OP
	OUC										184.2	188.4	OP
											228	**235.4**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	2025														
LAK	MCINTOSH	MREP 1-3	POLK	IC	NG	PL	NA	NA	0	1 / 2025	60	60	59.5	59.5	V
SEC	Shady Hill Generating Station	1	PASCO	CT	NG	PL	NA	NA	0	1 / 2025	0	0	0	-175	OT
SEC	Shady Hill Generating Station	2	PASCO	CT	NG	PL	NA	NA	0	1 / 2025	0	0	0	-175	OT
SEC	Shady Hill Generating Station	3	PASCO	CT	NG	PL	NA	NA	0	1 / 2025	0	0	0	-175	OT
TEC	SOUTH TAMPA RESILIENCY PROJECT	MPS01	HILLSBOROUGH	IC	NG	PL	NA	NA	0	2 / 2025	18.8	18.8	18.8	18.8	OP
TEC	SOUTH TAMPA RESILIENCY PROJECT	MPS02	HILLSBOROUGH	IC	NG	PL	NA	NA	0	2 / 2025	18.8	18.8	18.8	18.8	OP
DEF	P. L. BARTOW	4AGT	PINELLAS	CT	NG	PL	DFO	TK	0	3 / 2025	0	0	0	10.1	RP
DEF	P. L. BARTOW	4BGT	PINELLAS	CT	NG	PL	DFO	TK	0	3 / 2025	0	0	0	10	RP
DEF	P. L. BARTOW	4CGT	PINELLAS	CT	NG	PL	DFO	TK	0	3 / 2025	0	0	0	9.3	RP
DEF	P. L. BARTOW	4DGT	PINELLAS	CT	NG	PL	DFO	TK	0	3 / 2025	0	0	0	9.5	RP
DEF	P. L. BARTOW	4ST	PINELLAS	CA	WH	NA	DFO	TK	0	3 / 2025	0	0	0	20.1	RP
TEC	POLK	1CA	POLK	CA	WH	NA	NA	NA	0	3 / 2025	-120	-120	-51	-51	OT
OUC	OSCEOLA GENERATING STATION	1	OSCEOLA	GT	NG	PL	DFO	TK	3	3 / 2025	157	157	157	157	OT
OUC	OSCEOLA GENERATING STATION	3	OSCEOLA	GT	NG	PL	DFO	TK	3	3 / 2025	157	157	157	157	OT
LWBU	TOM G. SMITH	S-3	PALM BEACH	ST	NG	PL	---		0	4 / 2025	0	0	0	0	RT
LWBU	TOM G. SMITH	S-5	PALM BEACH	CA	WH	NA	---		0	4 / 2025	0	0	0	0	RT
DEF	HINES ENERGY COMPLEX	2GT1	POLK	CT	NG	PL	DFO	TK	0	4 / 2025	32.5	32.5	32.5	32.5	RP
DEF	HINES ENERGY COMPLEX	2GT2	POLK	CT	NG	PL	DFO	TK	0	4 / 2025	32.5	32.5	32.5	32.5	RP
FPL	PEA RIDGE	1	SANTA ROSA	GT	NG	PL	NA	NA	0	4 / 2025	-4	-5	-4	-5	RT
FPL	PEA RIDGE	2	SANTA ROSA	GT	NG	PL	NA	NA	0	4 / 2025	-4	-5	-4	-5	RT
FPL	PEA RIDGE	3	SANTA ROSA	GT	NG	PL	NA	NA	0	4 / 2025	-4	-5	-4	-5	RT
FPL	SANFORD	5CTA	VOLUSIA	CT	NG	PL	NA	NA	0	4 / 2025	2.5	6.5	2.5	6.5	A
FPL	SANFORD	5CTB	VOLUSIA	CT	NG	PL	NA	NA	0	4 / 2025	2.5	6.5	2.5	6.5	A
FPL	SANFORD	5CTC	VOLUSIA	CT	NG	PL	NA	NA	0	4 / 2025	2.5	6.5	2.5	6.5	A
FPL	SANFORD	5CTD	VOLUSIA	CT	NG	PL	NA	NA	0	4 / 2025	2.5	6.5	2.5	6.5	A
FPL	MARTIN	4GT1	MARTIN	CT	NG	PL	DFO	TK	0	4 / 2025	0	4.5	0	4.5	A
FPL	MARTIN	4GT2	MARTIN	CT	NG	PL	---		0	4 / 2025	0	4.5	0	4.5	A
TEC	BIG BEND	4	HILLSBOROUGH	ST	BIT	WA	NG	PL	0	4 / 2025	-57	-62	-57	-62	D
TEC	Lake Mabel Battery Storage	BESS1	POLK	BA	NA	NA	NA	NA	0	4 / 2025	40	40	40	40	V
TEC	Wimauma Battery Storage	BESS1	HILLSBOROUGH	BA	NG	NA	NA	NA	0	4 / 2025	40	40	40	40	V
FPL	TURKEY POINT	5CTA	DADE	CT	NG	PL	DFO	TK	3	5 / 2025	2	0.8	2	0.8	A
FPL	TURKEY POINT	5CTB	DADE	CT	NG	PL	DFO	TK	3	5 / 2025	2	0.8	2	0.8	A
FPL	TURKEY POINT	5CTC	DADE	CT	NG	PL	DFO	TK	3	5 / 2025	2	0.8	2	0.8	A
FPL	TURKEY POINT	5CTD	DADE	CT	NG	PL	DFO	TK	3	5 / 2025	2	0.8	2	0.8	A
DEF	Osprey Energy Center	GT1	POLK	CT	NG	PL	DFO	TK	2	6 / 2025	105.4	106.4	104.4	105.4	OT
DEF	Osprey Energy Center	GT2	POLK	CT	NG	PL	DFO	TK	2	6 / 2025	107.4	108.4	106.4	107.4	OT
DEF	Osprey Energy Center	ST1	POLK	ST	NG	PL	DFO	TK	2	6 / 2025	170.2	163.2	160.2	153.2	OT

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COMMERICAL IN-SERVICE	GROSS CAPABILITY (MW)		NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	TYPE	TRANS.	TYPE	TRANS.	BURN)	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
TEC	POLK	1CT	POLK	CT	PC	TK	NG	PL	0	6 / 2025	21	34	21	34	A
FPL	2025 GULF BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	10 / 2025	349.4	521.5	349.4	521.5	P
DEF	Osprey Energy Center	GT1	POLK	CT	NG	PL	DFO	TK	2	11 / 2025	0	20	0	20	RP
DEF	Osprey Energy Center	GT2	POLK	CT	NG	PL	DFO	TK	2	11 / 2025	0	20	0	20	RP
DEF	TIGER BAY	1GT	POLK	CT	NG	PL	---		0	11 / 2025	22	22	22	22	RP
DEF	CITRUS COMBINED CYCLE STATION	1GTA	CITRUS	CT	NG	PL	NA	NA	0	11 / 2025	11	11	11	11	RP
DEF	CITRUS COMBINED CYCLE STATION	1GTB	CITRUS	CT	NG	PL	NA	NA	0	11 / 2025	11	11	11	11	RP
FMPA	STANTON	1	ORANGE	ST	BIT	RR	NA	NA	0	12 / 2025	-118.5	-118.5	-118.5	-118.5	RT
KUA	STANTON	1	ORANGE	ST	BIT	RR	NA	NA	0	12 / 2025	-22	-22	-21.5	-21.5	RT
TEC	South Tampa Resiliency Project	MPS03	HILLSBOROUGH	IC	NG	PL	NA	NA	0	12 / 2025	18.8	18.8	18.8	18.8	V
TEC	South Tampa Resilience Project	MPS04	HILLSBOROUGH	IC	NG	PL	NA	NA	0	12 / 2025	18.8	18.8	18.8	18.8	V
TEC	Bayside Battery Storage	BESS1	HILLSBOROUGH	BA	NA	NA	NA	NA	0	12 / 2025	20	20	20	20	P
											2025 TOTAL:		**1,157**	**923**	
	2026														
FPL	2026 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2026	997	1420	997	1420	P
FMPA	Orange	1CT	POLK	CT	NG	PL	NA	NA	0	1 / 2026	39.5	39.5	39.5	39.5	OP
FMPA	Orange	2CT	POLK	CT	NG	PL	NA	NA	0	1 / 2026	39.5	39.5	39.5	39.5	OP
FMPA	Orange	3CA	POLK	CA	WH	NA	NA	NA	0	1 / 2026	25	25	25	25	OP
OUC	OSCEOLA GENERATING STATION	2	OSCEOLA	GT	NG	PL	DFO	TK	3	3 / 2025	157	157	157	157	OT
DEF	CITRUS COMBINED CYCLE STATION	2GTA	CITRUS	CT	NG	PL	NA	NA	0	4 / 2026	11	22	11	22	RP
DEF	CITRUS COMBINED CYCLE STATION	2GTB	CITRUS	CT	NG	PL	NA	NA	0	4 / 2026	11	22	11	22	RP
FMPA	TREASURE COAST ENERGY CTR	1	ST LUCIE	CT	NG	PL	DFO	TK	0	4 / 2026	9.5	9.5	9.5	9.5	A
FMPA	TREASURE COAST ENERGY CTR	1	ST LUCIE	CA	WH	NA	DFO	TK	0	4 / 2026	9.5	9.5	9.5	9.5	A
OUC	STANTON	1	ORANGE	ST	BIT	RR	NA	NA	0	5 / 2026	-321	-321	-310.6	-310.6	OT
DEF	HINES ENERGY COMPLEX	3GT1	POLK	CT	NG	PL	DFO	TK	0	5 / 2026	32.5	32.5	32.5	32.5	RP
DEF	HINES ENERGY COMPLEX	3GT2	POLK	CT	NG	PL	DFO	TK	0	5 / 2026	32.5	32.5	32.5	32.5	RP
DEF	P. L. BARTOW	4AGT	PINELLAS	CT	NG	PL	DFO	TK	0	5 / 2026	9.5	15.7	9.5	15.7	RP
DEF	P. L. BARTOW	4BGT	PINELLAS	CT	NG	PL	DFO	TK	0	5 / 2026	9.5	15.7	9.5	15.7	RP
DEF	P. L. BARTOW	4CGT	PINELLAS	CT	NG	PL	DFO	TK	0	5 / 2026	9.5	15.8	9.5	15.8	RP
DEF	P. L. BARTOW	4DGT	PINELLAS	CT	NG	PL	DFO	TK	0	5 / 2026	9.5	15.8	9.5	15.8	RP
DEF	BAYBORO	P1	PINELLAS	GT	DFO	WA	NA	NA	0	10 / 2026	-37	-55	-37	-55	RT
DEF	BAYBORO	P2	PINELLAS	GT	DFO	WA	NA	NA	0	10 / 2026	-18.5	-27.5	-18.5	-27.5	RT
DEF	BAYBORO	P3	PINELLAS	GT	DFO	WA	NA	NA	0	10 / 2026	-40	-54	-40	-54	RT
DEF	BAYBORO	P4	PINELLAS	GT	DFO	WA	NA	NA	0	10 / 2026	-41	-56	-41	-56	RT
TEC	POLK	2	POLK	CT	NG	PL	DFO	TK	3	11 / 2026	21.4	15.4	21.4	15.4	A

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
TEC	POLK	2 St	POLK	CA	WH	NA	NA	NA	0	11 / 2026	16.8	12.1	16.8	12.1	A
TEC	POLK	5	POLK	CT	NG	PL	NA	NA	0	11 / 2026	21.4	15.4	21.4	15.4	A
DEF	HINES ENERGY COMPLEX	4GT1	POLK	CT	NG	PL	DFO	TK	0	11 / 2026	11	16.5	11	16.5	RP
DEF	HINES ENERGY COMPLEX	4GT2	POLK	CT	NG	PL	DFO	TK	0	11 / 2026	11	16.5	11	16.5	RP
SEC	Shady Hills Energy Center	1	PASCO	CC	NG	PL	NA	NA	0	12 / 2026	546	575	546	575	U
											2026 TOTAL:		**1,583**	**2,020**	
	2027														
FPL	2027 UNSITED BATERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2027	599	820	432	820	P
FPL	WEST COUNTY	3GT1	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	3GT2	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	3GT3	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT1A	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT1B	PALM BEACH	CT	NG	PL	DFO	TK	0	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT1C	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT2A	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT2B	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
FPL	WEST COUNTY	CT2C	PALM BEACH	CT	NG	PL	DFO	TK	2	1 / 2027	0	3	0	3	A
DEF	BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	3 / 2027	90	90	90	90	P
OUC	STANTON	2	ORANGE	ST	NG	PL	NA	NA	0	4 / 2027	0	0	0	0	OT
FPL	MARTIN	8CTA	MARTIN	CT	NG	PL	DFO	NA	0	5 / 2027	4.8	1.2	4.8	1.2	A
FPL	MARTIN	8CTB	MARTIN	CT	NG	PL	DFO	NA	0	5 / 2027	4.8	1.2	4.8	1.2	A
FPL	MARTIN	8CTC	MARTIN	CT	NG	PL	DFO	TK	3	5 / 2027	4.8	1.2	4.8	1.2	A
FPL	MARTIN	8CTD	MARTIN	CT	NG	PL	DFO	TK	3	5 / 2027	4.8	1.2	4.8	1.2	A
TEC	POLK	3	POLK	CT	NG	PL	DFO	TK	3	6 / 2027	21.4	15.4	21.4	15.4	A
TEC	POLK	4	POLK	CT	NG	PL	NA	NA	0	6 / 2027	21.4	15.4	21.4	15.4	A
FPL	MANATEE	3CTA	MANATEE	CT	NG	PL	NA	NA	0	6 / 2027	7.3	1.2	7.3	1.2	A
FPL	MANATEE	3CTB	MANATEE	CT	NG	PL	NA	NA	0	6 / 2027	7.3	1.2	7.3	1.2	A
FPL	MANATEE	3CTC	MANATEE	CT	NG	PL	NA	NA	0	6 / 2027	7.3	1.2	7.3	1.2	A
FPL	MANATEE	3CTD	MANATEE	CT	NG	PL	NA	NA	0	6 / 2027	7.3	1.2	7.3	1.2	A
TEC	POLK	2 St	POLK	CA	WH	NA	NA	NA	0	6 / 2027	16.8	12.1	16.8	12.1	A
DEF	DEBARY	P2	VOLUSIA	GT	DFO	TK	NA	NA	0	6 / 2027	-45	-57	-45	-57	RT
DEF	DEBARY	P3	VOLUSIA	GT	DFO	TK	NA	NA	0	6 / 2027	-45	-59	-45	-59	RT
DEF	DEBARY	P4	VOLUSIA	GT	DFO	TK	NA	NA	0	6 / 2027	-46	-59	-46	-59	RT
DEF	DEBARY	P5	VOLUSIA	GT	DFO	TK	NA	NA	0	6 / 2027	-45	-58	-45	-58	RT
DEF	DEBARY	P6	VOLUSIA	GT	DFO	TK	NA	NA	0	6 / 2027	-46	-59	-46	-59	RT
DEF	P. L. BARTOW	P1	PINELLAS	GT	DFO	WA	NA	NA	0	6 / 2027	-41	-50	-41	-50	RT

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
DEF	P. L. BARTOW	P3	PINELLAS	GT	DFO	WA	NA	NA	0	6 / 2027	-41	-51	-41	-51	RT
FMPA	ST. LUCIE	2	ST LUCIE	ST	NUC	TK	NA	NA	0	10 / 2027	-0.3	-0.3	-0.3	-0.3	OT
TEC	Future Battery Storage 1	BESS1	UNKNOWN	BA	NA	NA	NA	NA	0	10 / 2027	20	20	20	20	P
TEC	Future Battery Storage 2	BESS1	UNKNOWN	BA	NA	NA	NA	NA	0	12 / 2027	75	75	75	75	P
FPL	LANSING SMITH	A	BAY	GT	DFO	TK	NA	NA	0	12 / 2027	-32	-40	-32	-40	RT
GRU	DEERHAVEN	FS01	ALACHUA	ST	NG	PL	RFO	TK	0	12 / 2027	-81	-81	-76	-76	RT
										2027 TOTAL:			**308**	**575**	
	2028														
FPL	2028 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2028	298	596	298	596	P
FMPA	STANTON	2	ORANGE	CT	NG	PL	NA	NA	0	1 / 2028	0	0	0	0	FC
FPL	MANATEE	3CTA	MANATEE	CT	NG	PL	NA	NA	0	1 / 2028	3.5	0.8	3.5	0.8	A
FPL	MANATEE	3CTB	MANATEE	CT	NG	PL	NA	NA	0	1 / 2028	3.5	0.8	3.5	0.8	A
FPL	MANATEE	3CTC	MANATEE	CT	NG	PL	NA	NA	0	1 / 2028	3.5	0.8	3.5	0.8	A
FPL	MANATEE	3CTD	MANATEE	CT	NG	PL	NA	NA	0	1 / 2028	3.5	0.8	3.5	0.8	A
SEC	Shady Hill Generating Station	1	PASCO	CT	NG	PL	NA	NA	0	1 / 2028	0	0	0	175	OT
SEC	Shady Hill Generating Station	2	PASCO	CT	NG	PL	NA	NA	0	1 / 2028	0	0	0	175	OT
SEC	Shady Hill Generating Station	3	PASCO	CT	NG	PL	NA	NA	0	1 / 2028	0	0	0	175	OT
DEF	SOLAR PLUS STORAGE	1b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2028	90	90	90	90	P
SEC	UNNAMED CT	1	UNKNOWN	CT	NG	PL	NA	NA	0	12 / 2028	393	453	393	453	P
										2028 TOTAL:			**795**	**1,667**	
	2029														
FPL	2029 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2029	316	596	247	596	P
DEF	BATTERY STORAGE	2	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2029	202.5	202.5	202.5	202.5	P
DEF	SOLAR PLUS STORAGE	2b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2029	90	90	90	90	P
FMPA	ST. LUCIE	2	ST LUCIE	ST	NUC	TK	NA	NA	0	10 / 2029	-1.5	-1.6	-1.5	-1.6	OT
FPL	GULF CLEAN ENERGY CENTER	5	ESCAMBIA	ST	NG	PL	NA	NA	0	12 / 2029	-75	-75	-75	-75	RT
FPL	PERDIDO	1	ESCAMBIA	IC	LFG	PL	NA	NA	0	12 / 2029	-1.5	-1.5	-1.5	-1.5	RT
FPL	PERDIDO	2	ESCAMBIA	IC	LFG	PL	NA	NA	0	12 / 2029	-1.5	-1.5	-1.5	-1.5	RT
FPL	GULF CLEAN ENERGY CENTER	4	ESCAMBIA	ST	NG	PL	NA	NA	0	12 / 2029	-75	-75	-75	-75	RT
										2029 TOTAL:			**385**	**734**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	2030														
FPL	2030 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2030	298	596	244	596	P
FMPA	CANE ISLAND	4CT	OSCEOLA	CT	NG	PL	NA	NA	0	1 / 2030	9.5	9.5	9.5	9.5	OT
FMPA	CANE ISLAND	4CW	OSCEOLA	CA	WH	NA	NA	NA	0	1 / 2030	9.5	9.5	9.5	9.5	OT
DEF	SOLAR PLUS STORAGE	3b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2030	90	90	90	90	P
JEA	NORTHSIDE	3	DUVAL	ST	NG	PL	RFO	WA	9	12 / 2030	-540	-540	-524	-524	RT
JEA	Advanced-Class 1x1 CC	99999	DUVAL	CC	NG	PL	DFO	TK	0	12 / 2030	576	669.8	576	669.8	P
SEC	UNNAMED CT	2	UNKNOWN	CT	NG	PL	NA	NA	0	12 / 2030	393	453	393	453	P
										2030 TOTAL:			**798**	**1,304**	
	2031														
FPL	2031 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2031	298	596	244	596	P
TEC	Future CT 1	1	UNKNOWN	CT	NG	PL	NA	NA	0	1 / 2031	222	247	222	247	P
DEF	SOLAR PLUS STORAGE	4b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2031	90	90	90	90	P
GRU	DEERHAVEN	GT01	ALACHUA	GT	NG	PL	DFO	TK	0	12 / 2031	-18	-23	-17.5	-22	RT
GRU	DEERHAVEN	GT02	ALACHUA	GT	NG	PL	DFO	TK	0	12 / 2031	-18	-23	-17.5	-22	RT
										2031 TOTAL:			**521**	**889**	
	2032														
FPL	2x0 MANATEE CT	1	MANATEE	CT	NG	PL	NA	NA	0	1 / 2032	469	475	469	475	P
DEF	SOLAR PLUS STORAGE	5b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2032	85	85	85	85	P
SEC	UNNAMED CC	1	UNKNOWN	CC	NG	PL	NA	NA	0	12 / 2032	559.4	619.6	559.4	619.6	P
										2032 TOTAL:			**1,113**	**1,180**	
	2033														
FPL	2033 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2033	424	1192	424	1192	P
DEF	UNDESIGNATED COMBUSTION TURBINE	P1	UNKNOWN	CT	NG	PL	DFO	TK	3	6 / 2033	245.5	263.6	245.5	263.6	P
DEF	UNDESIGNATED COMBUSTION TURBINE	P2	UNKNOWN	CT	NG	PL	DFO	TK	3	6 / 2033	245.5	263.6	245.5	263.6	P
DEF	SOLAR PLUS STORAGE	6b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2033	70	70	70	70	P
										2033 TOTAL:			**985**	**1,789**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	2034														
FPL	2034 UNSITED BATTERY STORAGE	1	UNKNOWN	BA	BS	NA	NA	NA	0	1 / 2034	350	1267	350	1267	P
DEF	UNDESIGNATED COMBUSTION TURBINE	P3	UNKNOWN	CT	NG	PL	DFO	TK	3	6 / 2034	224.3	232.5	224.3	232.5	P
DEF	UNDESIGNATED COMBUSTION TURBINE	P4	UNKNOWN	CT	NG	PL	DFO	TK	3	6 / 2034	224.3	232.5	224.3	232.5	P
DEF	CRYSTAL RIVER	4	CITRUS	ST	BIT	WA	BIT	RR	0	6 / 2034	-769	-767	-712	-721	RT
DEF	CRYSTAL RIVER	5	CITRUS	ST	BIT	WA	BIT	RR	0	6 / 2034	-755	-778	-710	-721	RT
DEF	SUWANNEE RIVER	P1	SUWANNEE	GT	NG	PL	DFO	TK	9	6 / 2034	-48	-65	-48	-65	RT
DEF	SUWANNEE RIVER	P2	SUWANNEE	GT	NG	PL	DFO	TK	0	6 / 2034	-48	-64	-48	-64	RT
DEF	SUWANNEE RIVER	P3	SUWANNEE	GT	NG	PL	DFO	TK	0	6 / 2034	-49	-65	-49	-65	RT
DEF	P. L. BARTOW	P2	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 2034	-41	-53	-41	-53	RT
DEF	P. L. BARTOW	P4	PINELLAS	GT	NG	PL	DFO	WA	8	6 / 2034	-45	-58	-45	-58	RT
DEF	INTERCESSION CITY	P1	OSCEOLA	GT	DFO	PL	---		0	6 / 2034	-45	-61	-45	-61	RT
DEF	INTERCESSION CITY	P2	OSCEOLA	GT	DFO	PL	---	---	0	6 / 2034	-46	-60	-46	-60	RT
DEF	INTERCESSION CITY	P3	OSCEOLA	GT	DFO	PL	---	---	0	6 / 2034	-46	-61	-46	-61	RT
DEF	INTERCESSION CITY	P4	OSCEOLA	GT	DFO	PL	---	---	0	6 / 2034	-46	-62	-46	-62	RT
DEF	INTERCESSION CITY	P5	OSCEOLA	GT	DFO	PL	---	---	0	6 / 2034	-45	-59	-45	-59	RT
DEF	INTERCESSION CITY	P6	OSCEOLA	GT	DFO	PL	---	---	0	6 / 2034	-47	-60	-47	-60	RT
DEF	SOLAR PLUS STORAGE	7b	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2034	70	70	70	70	P
DEF	BATTERY STORAGE	3	UNKNOWN	BA	BS	NA	NA	NA	0	6 / 2034	210	210	210	210	P
FPL	SCHERER	3	MONROE GA	ST	BIT	RR	NA	NA	0	12 / 2034	-215	-215	-215	-215	RT
FPL	MANATEE	1	MANATEE	ST	NG	PL	RFO	WA	21	12 / 2034	0	0	0	-819	OS-RT
FPL	MANATEE	2	MANATEE	ST	NG	PL	RFO	WA	21	12 / 2034	0	0	0	-819	OS-RT
										2034 TOTAL:			**-1,064**	**-313**	
										FRCC FUTURE EXCLUDING SOLAR:			**6,580**	**10,768**	
										FRCC FUTURE SOLAR:			**3,147**	**1,742**	
										FUTURE TOTAL:			**9,727**	**12,511**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 - Solar
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERICAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	2025									
FPL	HOLOPAW SOLAR	1	PALM BEACH	PV	SUN	1 / 2025	74.5	3.3	2.9	P
FPL	FAWN SOLAR	1	MARTIN	PV	SUN	1 / 2025	74.5	22.9	2.8	P
FPL	HOG BAY SOLAR	1	DESOTO	PV	SUN	1 / 2025	74.5	19.5	1.2	P
FPL	GREEN PASTURE SOLAR	1	CHARLOTTE	PV	SUN	1 / 2025	74.5	20.2	1.3	P
FPL	THOMAS CREEK SOLAR	1	NASSAU	PV	SUN	1 / 2025	74.5	21.1	0.4	P
FPL	FOX TRAIL SOLAR	1	BREVARD	PV	SUN	1 / 2025	74.5	22.4	1.9	P
FPL	SWALLOWTAIL SOLAR	1	WALTON	PV	SUN	1 / 2025	74.5	30.6	0	P
FPL	REDLANDS SOLAR	1	DADE	PV	SUN	1 / 2025	74.5	22.3	3.7	P
FPL	SPECKLED PERCH SOLAR	1	OKEECHOBEE	PV	SUN	1 / 2025	74.5	19.7	2.1	P
FPL	BIG WATER SOLAR	1	OKEECHOBEE	PV	SUN	1 / 2025	74.5	20.3	2	P
FPL	LONG CREEK SOLAR	1	MANATEE	PV	SUN	1 / 2025	74.5	21.1	1.3	P
FPL	TENMILE CREEK SOLAR	1	CALHOUN	PV	SUN	1 / 2025	74.5	29.6	0	P
DEF	SUNDANCE SOLAR POWER PLANT	PV1	MADISON	PV	SUN	6 / 2025	74.5	25.8	3.7	P
DEF	Lake Placid Solar Power Plant	PV1	HIGHLANDS	PV	SUN	6 / 2025	45	10.6	1	RP
TEC	Long Branch Solar	1	MANATEE	PV	SUN	12 / 2025	74.5	3.7	0	U
TEC	Cottonmouth Solar	1	HILLSBOROUGH	PV	SUN	12 / 2025	74.5	3.7	0	U
	Solar Degredation							-11.6	0	
							2025 TOTAL:	**1,128**	**633**	
	2026									
FPL	FLATFORD SOLAR	1	MANATEE	PV	SUN	1 / 2026	74.5	2.5	4.8	P
FPL	MARE BRANCH SOLAR	1	DESOTO	PV	SUN	1 / 2026	74.5	23.1	2.4	P
FPL	PRICE CREEK SOLAR	1	COLUMBIA	PV	SUN	1 / 2026	74.5	6.4	0	P
FPL	SWAMP CABBAGE SOLAR	1	HENDRY	PV	SUN	1 / 2026	74.5	21.7	3.4	P

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 - Solar
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERICAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
FPL	BIG BROOK SOLAR	1	CALHOUN	PV	SUN	1 / 2026	74.5	21	0	P
FPL	MALLARD SOLAR	1	BREVARD	PV	SUN	1 / 2026	74.5	3.8	2.3	P
FPL	BOARDWALK SOLAR	1	COLLIER	PV	SUN	1 / 2026	74.5	8.8	2.1	P
FPL	GOLDENROD SOLAR	1	COLLIER	PV	SUN	1 / 2026	74.5	3.9	2	P
DEF	RATTLER SOLAR POWER PLANT	PV1	HERNANDO	PV	SUN	1 / 2026	74.9	25.8	3.7	P
DEF	HALF MOON SOLAR POWER PLANT	PV1	SUMTER	PV	SUN	2 / 2026	74.9	25.8	3.7	P
FPL	NORTH ORANGE SOLAR	1	ST LUCIE	PV	SUN	4 / 2026	74.5	3.8	2.5	P
FPL	SEA GRAPE SOLAR	1	ST LUCIE	PV	SUN	4 / 2026	74.5	3.8	2.5	P
FPL	CLOVER SOLAR	1	ST LUCIE	PV	SUN	4 / 2026	74.5	3.8	2.5	P
FPL	SAND PINE SOLAR	1	CALHOUN	PV	SUN	4 / 2026	74.5	9.8	0	P
DEF	BAILEY MILL SOLAR POWER PLANT	PV1	JEFFERSON	PV	SUN	5 / 2026	74.9	25.8	3.7	P
DEF	JUMPER CREEK SOLAR PLANT	PV1	SUMTER	PV	SUN	6 / 2026	74.9	27.3	3.3	P
FPL	INLET SOLAR	1	INDIAN RIVER	PV	SUN	10 / 2026	74.5	4.7	2.3	P
DEF	TURNPIKE SOLAR POWER PLANT	PV1	OSCEOLA	PV	SUN	12 / 2026	74.9	27.3	3.3	P
DEF	LONESOME CAMP SOLAR POWER PLANT	PV1	OSCEOLA	PV	SUN	12 / 2026	74.9	27.3	3.3	P
DEF	BANNER SOLAR POWER PLANT	PV1	COLUMBIA	PV	SUN	12 / 2026	74.5	27.3	3.3	P
TEC	Keene Branch Solar	1	HILLSBOROUGH	PV	SUN	12 / 2026	74.5	3.7	0	P
TEC	Curiosity Creek Solar	1	HILLSBOROUGH	PV	SUN	12 / 2026	54.3	2.7	0	P
TEC	Brewster Solar	1	POLK	PV	SUN	12 / 2026	42.7	0.6	0	P
TEC	Mattaniah Solar	1	HILLSBOROUGH	PV	SUN	12 / 2026	55	0.8	0	P
	Solar Degredation							-14.7	0	
								297	**51**	
	2027									
FPL	HENDRY SOLAR	1	HENDRY	PV	SUN	1 / 2027	74.5	3.9	2.4	P
FPL	TANGELO SOLAR	1	OKEECHOBEE	PV	SUN	1 / 2027	74.5	3.9	2.4	P

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 - Solar
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERICAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
FPL	WOOD STORK SOLAR	1	ST LUCIE	PV	SUN	1 / 2027	74.5	3.9	2.4	P
FPL	INDRIO SOLAR	1	ST LUCIE	PV	SUN	1 / 2027	74.5	3.9	2.4	P
FPL	MIDDLE LAKE SOLAR	1	MADISON	PV	SUN	4 / 2027	74.5	3.9	2.4	P
FPL	AMBERSWEET SOLAR	1	INDIAN RIVER	PV	SUN	4 / 2027	74.5	3.9	2.4	P
FPL	COUNTY LINE SOLAR	1	CHARLOTTE	PV	SUN	4 / 2027	74.5	3.9	2.4	P
FPL	SADDLE SOLAR	1	DESOTO	PV	SUN	4 / 2027	74.5	3.9	2.4	P
DEF	SOLAR	23	UNKNOWN	PV	SUN	6 / 2027	149.8	50.2	6.1	P
FPL	HARDWOOD HAMMOCK SOLAR	1	WALTON	PV	SUN	7 / 2027	74.5	3.9	2.4	P
FPL	COCOPLUM SOLAR	1	HENDRY	PV	SUN	7 / 2027	74.5	3.9	2.4	P
FPL	CATFISH SOLAR	1	OKEECHOBEE	PV	SUN	7 / 2027	74.5	3.9	2.4	P
FPL	MAPLE TRAIL SOLAR	1	BAKER	PV	SUN	7 / 2027	74.5	3.9	2.4	P
FPL	JOSHUA CREEK SOLAR	1	DESOTO	PV	SUN	10 / 2027	74.5	3.9	2.4	P
FPL	PINECONE SOLAR	1	DESOTO	PV	SUN	10 / 2027	74.5	3.9	2.4	P
FPL	SPANISH MOSS SOLAR	1	ST LUCIE	PV	SUN	10 / 2027	74.5	3.9	2.4	P
FPL	VERNIA SOLAR	1	INDIAN RIVER	PV	SUN	10 / 2027	74.5	3.9	2.4	P
TEC	Brewster Ph. II Solar	1	POLK	PV	SUN	12 / 2027	15.6	0.2	0	P
TEC	FS1	1	UNKNOWN	PV	SUN	12 / 2027	74.5	1.1	0	P
TEC	FS2	1	UNKNOWN	PV	SUN	12 / 2027	74.5	1.1	0	P
DEF	SOLAR	24	UNKNOWN	PV	SUN	12 / 2027	149.8	50.2	6.1	P
	Solar Degredation							-15.5	0	
							2027 TOTAL:	**150**	**51**	
	2028									
FPL	2028 Unsited Solar	1	UNKNOWN	PV	SUN	1 / 2028	1490	79.1	0	P
DEF	SOLAR PLUS STORAGE	1a	UNKNOWN	PV	SUN	6 / 2028	149.8	41.2	6.1	P
DEF	SOLAR	25	UNKNOWN	PV	SUN	6 / 2028	224.7	61.8	9.2	P
TEC	FS3	1	UNKNOWN	PV	SUN	12 / 2028	74.5	1.1	0	P
TEC	FS4	1	UNKNOWN	PV	SUN	12 / 2028	55	0.8	0	P
TEC	FS5	1	UNKNOWN	PV	SUN	12 / 2028	74.5	1.1	0	P
	Solar Degredation							-15.9	0	
							2028 TOTAL:	**169**	**15**	
	2029									
FPL	2029 Unsited Solar	1	UNKNOWN	PV	SUN	1 / 2029	1788	94.9	0	P
DEF	SOLAR	26	UNKNOWN	PV	SUN	6 / 2029	224.7	61.8	9.2	P
DEF	SOLAR PLUS STORAGE	2a	UNKNOWN	PV	SUN	6 / 2029	149.8	32.2	6.1	P
TEC	FS6	1	UNKNOWN	PV	SUN	12 / 2029	149	1.5	0	P

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 - Solar
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERICAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	Solar Degredation							-16.4	0	
							2029 TOTAL:	**174**	**15**	
	2030									
FPL	2030 Unsited Solar	1	UNKNOWN	PV	SUN	1 / 2030	2235	118.6	0	P
DEF	SOLAR	27	UNKNOWN	PV	SUN	6 / 2030	224.7	48.3	9.2	P
DEF	SOLAR PLUS STORAGE	3a	UNKNOWN	PV	SUN	6 / 2030	149.8	32.2	6.1	P
TEC	FS7	1	UNKNOWN	PV	SUN	12 / 2030	149	1.5	0	P
	Solar Degredation							-16.8	0	
							2030 TOTAL:	**184**	**15**	
	2031									
FPL	2031 UNSITED SOLAR	1	UNKNOWN	PV	SUN	1 / 2031	2235	118.6	0	P
DEF	SOLAR	29	UNKNOWN	PV	SUN	6 / 2031	374.5	58	15.4	P
DEF	SOLAR	28	UNKNOWN	PV	SUN	6 / 2031	74.9	16.1	3.1	P
DEF	SOLAR PLUS STORAGE	4a	UNKNOWN	PV	SUN	6 / 2031	149.8	23.2	6.1	P
TEC	FS8	1	UNKNOWN	PV	SUN	12 / 2031	74.5	0.7	0	P
								-16.4	0	
							2031 TOTAL:	**721**	**913**	
	2032									
FPL	2032 UNSITED SOLAR	1	UNKNOWN	PV	SUN	1 / 2032	2235	119	0	P
DEF	SOLAR	30	UNKNOWN	PV	SUN	6 / 2032	74.9	11.6	3.1	P
DEF	SOLAR	31	UNKNOWN	PV	SUN	6 / 2032	374.5	35.6	15.4	P
DEF	SOLAR PLUS STORAGE	5a	UNKNOWN	PV	SUN	6 / 2032	149.8	14.2	6.1	P
TEC	FS9	1	UNKNOWN	PV	SUN	12 / 2032	74.5	0.7	0	P
	Solar Degradation							-16.6	0	
							2032 TOTAL:	**165**	**25**	
	2033									
FPL	2033 UNSITED SOLAR	1	UNKNOWN	PV	SUN	1 / 2033	2235	119	0	P
DEF	SOLAR	32	UNKNOWN	PV	SUN	6 / 2033	449.4	42.7	18.4	P
DEF	SOLAR PLUS STORAGE	6a	UNKNOWN	PV	SUN	6 / 2033	149.8	14.2	6.1	P
TEC	FS10	1	UNKNOWN	PV	SUN	12 / 2033	74.5	0.7	0	P
								-16.9	0	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 1.1 - Solar
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	COMMERICAL IN-SERVICE MO. / YEAR	NAMEPLATE CAPABILITY$_{AC}$ (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
							2033 TOTAL:	**160**	**25**	
	2034									
FPL	2034 UNSITED SOLAR	1	UNKNOWN	PV	SUN	1 / 2034	2235	119	0	P
DEF	SOLAR PLUS STORAGE	7a	UNKNOWN	PV	SUN	6 / 2034	149.8	14.2	6.1	P
DEF	SOLAR	33	UNKNOWN	PV	SUN	6 / 2034	449.4	42.7	18.4	P
TEC	FS11	1	UNKNOWN	PV	SUN	12 / 2034	74.5	0.7	0	P
								-17.1	0	
							2034 TOTAL:	**160**	**25**	
							FRCC FUTURE EXCLUDING SOLAR:	**6,580**	**10,768**	
							FRCC FUTURE SOLAR:	**3,147**	**1,742**	
							FUTURE TOTAL:	**9,727**	**12,511**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC FORM 10
SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE REGION	OUTSIDE REGION	REGIONAL IMPORTS	REGIONAL EXPORTS	NON-UTILITY PURCHASES	AVAILABLE CAPACITY	TOTAL PEAK DEMAND	LOAD MANAGEMENT & INT.		PEAK DEMAND	LOAD MANAGEMENT & INT.	
YEAR	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% OF PEAK	(MW)	(MW)	% OF PEAK
2025	59,809	0	381	0	2,877	63,067	53,933	9,134	17%	50,588	12,479	25%
2026	61,419	0	281	0	2,798	64,498	54,477	10,021	18%	51,126	13,372	26%
2027	62,392	0	281	0	2,197	64,870	54,933	9,937	18%	51,576	13,294	26%
2028	63,031	0	281	0	1,837	65,149	55,377	9,772	18%	52,020	13,129	25%
2029	64,139	0	281	0	1,747	66,167	56,099	10,068	18%	52,739	13,428	25%
2030	64,521	0	281	0	1,591	66,393	56,666	9,727	17%	53,298	13,095	25%
2031	65,723	0	281	0	1,714	67,719	57,414	10,305	18%	54,035	13,684	25%
2032	66,407	0	281	0	1,328	68,016	58,267	9,749	17%	54,879	13,137	24%
2033	68,111	0	281	0	965	69,357	58,972	10,385	18%	55,572	13,785	25%
2034	67,421	0	281	0	892	68,594	59,724	8,870	15%	56,312	12,282	22%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING		NET FIRM	RESERVE MARGIN WITH EXERCISING	
	INSIDE REGION	OUTSIDE REGION	REGIONAL IMPORTS	REGIONAL EXPORTS	NON-UTILITY PURCHASES	AVAILABLE CAPACITY	TOTAL PEAK DEMAND	LOAD MANAGEMENT & INT.		PEAK DEMAND	LOAD MANAGEMENT & INT.	
YEAR	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% OF PEAK	(MW)	(MW)	% OF PEAK
2025 / 26	60,116	0	409	0	2,543	63,068	48,628	14,440	30%	45,501	17,567	39%
2026 / 27	61,498	0	309	0	2,504	64,312	49,209	15,103	31%	46,074	18,238	40%
2027 / 28	62,392	0	309	0	1,305	64,006	49,875	14,131	28%	46,741	17,265	37%
2028 / 29	63,546	0	309	0	1,218	65,072	50,763	14,309	28%	47,631	17,441	37%
2029 / 30	64,313	0	309	0	1,063	65,685	51,487	14,198	28%	48,350	17,335	36%
2030 / 31	65,860	0	309	0	1,063	67,232	52,096	15,136	29%	48,953	18,279	37%
2031 / 32	66,405	0	309	0	713	67,427	52,809	14,618	28%	49,662	17,765	36%
2032 / 33	68,325	0	309	0	282	68,916	53,537	15,379	29%	50,383	18,533	37%
2033 / 34	70,213	0	309	0	282	70,804	54,232	16,572	31%	51,075	19,729	39%
2034 / 35	68,657	0	309	0	165	69,130	54,931	14,199	26%	51,767	17,363	34%

NOTE - COLUMN 11: NET FIRM PEAK DEMAND = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

2025
FRCC Form 11
CONTRACTED FIRM IMPORTS AND FIRM EXPORTS
FROM/TO OUTSIDE THE FRCC REGION AT TIME OF PEAK - MW
AS OF JANUARY 1, 2025

SUMMER

	IMPORTS				EXPORTS	NET INTER-
YEAR	FPL	JEA	SEC	TOTAL	TOTAL	CHANGE
2025	81	200	100	381	0	381
2026	81	200	0	281	0	281
2027	81	200	0	281	0	281
2028	81	200	0	281	0	281
2029	81	200	0	281	0	281
2030	81	200	0	281	0	281
2031	81	200	0	281	0	281
2032	81	200	0	281	0	281
2033	81	200	0	281	0	281
2034	81	200	0	281	0	281

WINTER

	IMPORTS				EXPORTS	NET INTER-
YEAR	FPL	JEA	SEC	TOTAL	TOTAL	CHANGE
2025/26	109	200	100	409	0	409
2026/27	109	200	0	309	0	309
2027/28	109	200	0	309	0	309
2028/29	109	200	0	309	0	309
2029/30	109	200	0	309	0	309
2030/31	109	200	0	309	0	309
2031/32	109	200	0	309	0	309
2032/33	109	200	0	309	0	309
2033/34	109	200	0	309	0	309
2034/35	109	200	0	309	0	309

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)		(17)
								GROSS CAPABILITY - MW		NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
													FIRM		UNCOMMITTED - MW		
		UNIT		FUEL TYPE		COM'L IN-SERVICE		SUM	WIN	SUM	WIN	UNIT	SUM	WIN	SUM	WIN	
UTILITY	FACILITY NAME	NO.	LOCATION	PRI	ALT	MO. / YEAR		(MW)	(MW)	(MW)	(MW)	TYPE	(MW)	(MW)	(MW)	(MW)	STATUS
DUKE ENERGY FLORIDA																	
	CITRUS WORLD	1	POLK	NG	DFO	11 /	1979	0.4	0.4	0.4	0.4	ST	0	0	0	0	NC
	CITRUS WORLD	4	POLK	NG	DFO	12 /	1987	4	4	4	4	ST	0	0	0	0	NC
	ORANGE COGEN (CFR-BIOGEN)	1	POLK	NG	---	6 /	1995	104	104	104	104	CS	104	104	0	0	C
	PASCO COUNTY RES. RECOV.	1	PASCO	MSW	---	3 /	1991	26	26	23	23	ST	0	0	0	0	C
	PINELLAS COUNTY RES. RECOV.	1	PINELLAS	MSW	---	4 /	1983	44.6	44.6	40	40	ST	0	0	0	0	C
	PINELLAS COUNTY RES. RECOV.	2	PINELLAS	MSW	---	6 /	1986	17.1	17.1	14.8	14.8	ST	0	0	0	0	C
	POTASH of SASKATCHEWAN	1	HAMILTON	WH	---	1 /	1980	16.2	16.2	15	15	ST	0	0	1	1	NC
	POTASH of SASKATCHEWAN	2	HAMILTON	WH	---	5 /	1986	28	28	27	27	ST	0	0	0.2	0.2	NC
			DEF TOTAL:										**104**	**104**	**1.2**	**1.2**	
FLORIDA MUNICIPAL POWER AGENCY																	
	CUTRALE		LAKE	NG	---	12 /	1987	4.6	4.6	4.6	4.6	CC	0	0	0	0	NC
	US SUGAR CORPORATION		HENDRY	OBS	---	2 /	1984	26.5	26.5	26.5	26.5	OT	0	0	0	0	NC
			FMPA TOTAL:										**0**	**0**	**0**	**0**	
FLORIDA POWER & LIGHT COMPANY																	
	BAY COUNTY RESOURCE RECOVER\	1	BAY	MSW	NA	1 /	2022	12.5	12.5	11	11	ST	0	0	11	0	NC
	BREVARD LANDFILL	1	BREVARD	MSW	---	5 /	2008	6	6	6	6	OT	0	0	0	0	NC
	BROWARD-SOUTH	1	BROWARD	MSW	---	4 /	1991	68	68	56	56	OT	3.5	3.5	0	0	C
	CHARLOTTE COUNTY LANDFILL	1	CHARLOTTE	MSW	---	10 /	2011	3	3	3	3	OT	0	0	0	0	NC
	GEORGIA PACIFIC	1	PUTNAM	WDS	---	5 /	1993	80	80	70	70	OT	0	0	0	0	NC
	INTERNATIONAL PAPER COMPANY	1	ESCAMBIA	WDS	NG	5 /	1983	28.1	28.1	21.4	21.4	ST	0	0	0	0	NC
	INTERNATIONAL PAPER COMPANY	2	ESCAMBIA	WDS	NG	5 /	1983	28.1	28.1	21.4	21.4	ST	0	0	0	0	NC
	LEE COUNTY SOLID WASTE	1	LEE	MSW	OTH	8 /	2007	59	59	55	55	OT	0	0	0	0	NC
	MIAMI DADE (RR)	1	DADE	MSW	OTH	12 /	1981	77	77	70	70	OT	0	0	0	0	NC
	NEW HOPE / OKEELANTA	1	PALM BEACH	OBS	NG	10 /	2006	129	129	105	105	OT	0	0	0	0	NC
	PENSACOLA CHRISTIAN COLLEGE	2	ESCAMBIA	NG	---	6 /	2006	14.4	14.4	14.4	14.4	IC	0	0	0	0	NC
	PENSACOLA CHRISTIAN COLLEGE	1	ESCAMBIA	NG	---	4 /	1988	3.3	3.3	3.3	3.3	ST	0	0	0	0	NC
	SARASOTA COUNTY LANDFILL	1	SARASOTA	MSW	---	2 /	2015	6	6	6	6	OT	0	0	0	0	NC
	SEMINOLE COUNTY LANDFILL	1	SEMINOLE	MSW	---	8 /	2007	6	6	6	6	OT	0	0	0	0	NC
	SOLUTIA	1	ESCAMBIA	NG	DFO	1 /	1954	5	5	5	5	ST	0	0	0	0	NC
	SOLUTIA	2	ESCAMBIA	NG	DFO	1 /	1954	5	5	5	5	ST	0	0	0	0	NC
	SOLUTIA	3	ESCAMBIA	NG	DFO	1 /	1954	6	6	6	6	ST	0	0	0	0	NC
	SOLUTIA	4	ESCAMBIA	NG	---	5 /	2005	86	86	86	86	ST	0	0	0	0	NC

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)		(17)
								GROSS CAPABILITY - MW		NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
													FIRM		UNCOMMITTED - MW		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	FUEL TYPE PRI	FUEL TYPE ALT	COM'L IN-SERVICE MO.	COM'L IN-SERVICE YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	UNIT TYPE	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	STATUS
	STONE CONTAINER	1	BAY	DFO	NG	1 /	1960	4	4	4	4	ST	0	0	0	0	NC
	STONE CONTAINER	2	BAY	BIT	---	1 /	1960	5	5	5	5	ST	0	0	0	0	NC
	STONE CONTAINER	3	BAY	WDS	NG	1 /	1960	8.6	8.6	8.6	8.6	ST	0	0	0	0	NC
	STONE CONTAINER	4	BAY	WDS	NG	1 /	1960	17.1	17.1	17.1	17.1	ST	0	0	0	0	NC
	TROPICANA	1	MANATEE	NG	OTH	3 /	1990	47	47	45	45	OT	0	0	0	0	NC
	WASTE MANAGEMENT (CCL)	1	BROWARD	MSW	OTH	5 /	2011	7.2	7.2	3.7	3.7	OT	0	0	0	0	NC
	WASTE MANAGEMENT (RE)	1	BROWARD	MSW	OTH	2 /	2000	11	11	6.3	6.3	OT	0	0	0	0	NC
			FPL TOTAL:										**3.5**	**3.5**	**11**	**0**	
JEA																	
	ANHEUSER BUSCH		DUVAL	NG	---	4 /	1988	0	0	8	9	ST	0	0	0	0	NC
	TRAILRIDGE	2	SARASOTA	LFG	---	2 /	2014	9	6	6	6	IC	6	6	0	0	C
	TRAILRIDGE	1	DUVAL	LFG	---	12 /	2008	6	9	9	9	IC	9	9	0	0	C
			JEA TOTAL:										**15**	**15**	**0**	**0**	
SEMINOLE ELECTRIC COOPERATIVE INC																	
	CITY OF TAMPA REFUSE-TO-ENERGY	1	HILLSBOROUGH	MSW	---	8 /	2011	20	20	20	20	ST	20	20	0	0	C
	HARDEE POWER STATION	CT2B	HARDEE	NG	DFO	1 /	2013	73	90	70	89	GT	70	62	0	27	C
	HARDEE POWER STATION	CT1A	HARDEE	NG	DFO	1 /	2013	73	89	72	88	CT	72	88	0	0	C
	HARDEE POWER STATION	CT1B	HARDEE	NG	DFO	1 /	2013	71	89	72	88	CT	72	88	0	0	C
	HARDEE POWER STATION	CT2A	HARDEE	WH	DFO	1 /	2013	76	90	70	89	GT	70	62	0	27	C
	HARDEE POWER STATION	ST1	HARDEE	NG	DFO	1 /	2013	71	91	76	91	CA	76	91	0	0	C
	HILLSB. WASTE TO ENERGY	2	HILLSBOROUGH	MSW	---	3 /	2010	9.5	9.5	9.5	9.5	ST	9.5	9.5	0	0	C
	HILLSB. WASTE TO ENERGY	3	HILLSBOROUGH	MSW	---	3 /	2010	9.5	9.5	9.5	9.5	ST	9.5	9.5	0	0	C
	HILLSB. WASTE TO ENERGY	4	HILLSBOROUGH	MSW	---	3 /	2010	9.5	9.5	9.5	9.5	ST	9.5	9.5	0	0	C
	HILLSB. WASTE TO ENERGY	1	HILLSBOROUGH	MSW	---	3 /	2010	9.5	9.5	9.5	9.5	ST	9.5	9.5	0	0	C
			SEC TOTAL:										**418**	**449**	**0**	**54**	
TAMPA ELECTRIC COMPANY																	
	MILLPOINT	1-3	HILLSBOROUGH	WH	NA	12 /	1995	8	8	8	8	ST	0	0	1	1	NC
	NEW WALES	1-2	POLK	WH	NA	12 /	1984	47	47	47	47	ST	0	0	1	1	NC
	RIDGEWOOD	1-2	HILLSBOROUGH	WH	NA	10 /	1992	41.7	41.7	41.7	41.7	ST	0	0	0.8	0.8	NC
	SOUTH PIERCE	1-2	POLK	WH	NA	9 /	1969	34	34	34	34	ST	0	0	3	3	NC

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)		(17)
								GROSS CAPABILITY - MW		NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
				FUEL TYPE		COM'L IN-SERVICE							FIRM		UNCOMMITTED - MW		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	PRI	ALT	MO.	/ YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	UNIT TYPE	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	STATUS
			TEC TOTAL:										0	0	5.8	5.8	

FRCC NON-UTILITY (Excluding Solar):	540.5	571.5
FRCC NON-UTILITY SOLAR:	146.4	0
FRCC NON-UTILITY TOTAL:	686.9	571.5

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0 - SOLAR
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	FUEL TYPE PRI	FUEL TYPE ALT	COM'L IN-SERVICE MO.	COM'L IN-SERVICE YEAR	NAMEPLATE CAPABILITY - MW (MW)	NET CAPABILITY - MW SUM (MW)	NET CAPABILITY - MW WIN (MW)	UNIT TYPE	POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW) FIRM SUM (MW)	POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW) FIRM WIN (MW)	STATUS
FLORIDA POWER & LIGHT COMPANY														
	FIRST SOLAR	1	DADE	SUN	NA	3 /	2010	0	0.2	0	PV	0	0	NC
			FPL TOTAL:									**0**	**0**	
JEA														
	BLAIR SITE SOLAR	1	DUVAL	SUN	---	1 /	2018	4	0	0	PV	0.8	0	C
	JACKSONVILLE SOLAR	1	DUVAL	SUN	NA	9 /	2010	12	0	0	PV	2.4	0	C
	NW JAX SOLAR	1	DUVAL	SUN	---	5 /	2017	7	0	0	PV	1.4	0	C
	OLD KINGS ROAD SOLAR	1	DUVAL	SUN	---	10 /	2018	1	0	0	PV	0.2	0	C
	OLD PLANK ROAD SOLAR FARM	1	DUVAL	SUN	NA	10 /	2017	3	0	0	PV	0.6	0	C
	SIMMONS ROAD SOLAR	1	DUVAL	SUN	---	1 /	2018	2	0	0	PV	0.4	0	C
	STARRATT SOLAR	1	DUVAL	SUN	NA	12 /	2017	5	0	0	PV	1	0	C
	SUNPORT SOLAR	1	DUVAL	SUN	---	12 /	2019	5	0	0	PV	1	0	C
			JEA TOTAL:									**7.8**	**0**	
LAKELAND CITY OF														
	AIRPORT PHASE 1	N/A	POLK	SUN	---	1 /	2012	2.2	2.2	2.2	PV	1.1	0	C
	AIRPORT PHASE 2	N/A	POLK	SUN	---	9 /	2012	2.7	2.7	2.7	PV	1.3	0	C
	AIRPORT PHASE 3	N/A	POLK	SUN	---	12 /	2016	3.1	3.1	3.1	PV	1.5	0	C
	BELLA VISTA	N/A	POLK	SUN	---	7 /	2015	6	6	6	PV	3	0	C
	LAKELAND CENTER	N/A	POLK	SUN	---	3 /	2010	0.2	0.2	0.2	PV	0.1	0	C
			LAK TOTAL:									**7**	**0**	
SEMINOLE ELECTRIC COOPERATIVE INC														
	Columbia Solar	1	COLUMBIA	SUN	NA	12 /	2024	74.5	74.5	74.5	PV	29.8	0	C
	Gadsden Solar	1	GADSDEN	SUN	NA	12 /	2024	74.5	74.5	74.5	PV	29.8	0	C
	Gilchrist Solar	1	GILCHRIST	SUN	NA	12 /	2024	74.5	74.5	74.5	PV	29.8	0	C
	TUPELO SOLAR	1	PUTNAM	SUN	NA	12 /	2024	74.5	74.5	74.5	PV	29.8	0	C
			SEC TOTAL:									**119.2**	**0**	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.0 - SOLAR
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
									NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW) FIRM		
UTILITY	FACILITY NAME	UNIT NO.	LOCATION	FUEL TYPE PRI	FUEL TYPE ALT	COM'L IN-SERVICE MO.	COM'L IN-SERVICE YEAR	NAMEPLATE CAPABILITY - MW (MW)	SUM (MW)	WIN (MW)	UNIT TYPE	SUM (MW)	WIN (MW)	STATUS
TALLAHASSEE CITY OF														
	FL SOLAR 1	1	LEON	SUN	NA	12 /	2017	20	19.6	19.6	PV	4	0	C
	FL SOLAR 4	4	LEON	SUN	NA	12 /	2019	45	42	42	PV	8.4	0	C
			TAL TOTAL:									**12.4**	**0**	

FRCC NON-UTILITY (Excluding Solar):	**540.5**	**571.5**
FRCC NON-UTILITY SOLAR:	**146.4**	**0.0**
FRCC NON-UTILITY TOTAL:	**686.9**	**571.5**

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.1
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2025 THROUGH DECEMBER 31, 2034

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)		(17)
						COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT		GROSS CAPABILITY - MW		NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
		UNIT		FUEL TYPE									FIRM		UNCOMMITTED - MW		
UTIL	FACILITY NAME	NO.	LOCATION	PRI.	ALT.	MO.	/ YEAR	SUM	WIN	SUM	WIN	TYPE	SUM	WIN	SUM	WIN	STATUS
	2025																
SEC	HILLSB. WASTE TO ENERGY	2	HILLSBOROUGH	MSW	---	3 /	2010	-9.5	-9.5	-9.5	-9.5	ST	-9.5	-9.5	0	0	CE
SEC	HILLSB. WASTE TO ENERGY	3	HILLSBOROUGH	MSW	---	3 /	2010	-9.5	-9.5	-9.5	-9.5	ST	-9.5	-9.5	0	0	CE
SEC	HILLSB. WASTE TO ENERGY	4	HILLSBOROUGH	MSW	---	3 /	2010	-9.5	-9.5	-9.5	-9.5	ST	-9.5	-9.5	0	0	CE
SEC	HILLSB. WASTE TO ENERGY	1	HILLSBOROUGH	MSW	---	3 /	2010	-9.5	-9.5	-9.5	-9.5	ST	-9.5	-9.5	0	0	CE
	2026																
SEC	CITY OF TAMPA REFUSE-TO-ENERGY	1	HILLSBOROUGH	MSW	---	8 /	2026	-20.0	-20.0	-20.0	-20.0	ST	-20	-20	0	0	CE
JEA	TRAILRIDGE	2	SARASOTA	LFG	NA	12 /	2026	-6.0	-6.0	-6.0	-6.0	IC	-6	-6	-6	-6	C
JEA	TRAILRIDGE	1	DUVAL	LFG	---	12 /	2026	-9.0	-9.0	-9.0	-9.0	IC	-9	-9	0	0	CE
FPL	BROWARD-SOUTH	1	BROWARD	MSW	NA	12 /	2026	0.0	0.0	0.0	0.0	OT	-3.5	-3.5	0	0	C
	2027 - 2032																
	No Entries																
	2033																
SEC	HARDEE POWER STATION	CT1A	HARDEE	NG	DFO	1 /	2033	-73.0	-89.0	-72.0	-88.0	CT	-72	-88	0	0	CE
SEC	HARDEE POWER STATION	CT1B	HARDEE	NG	DFO	1 /	2033	-73.0	-89.0	-72.0	-88.0	CT	-72	-88	0	0	CE
SEC	HARDEE POWER STATION	CT2A	HARDEE	NG	DFO	1 /	2033	-71.0	-90.0	-70.0	-89.0	GT	-70	-62	0	27	CE
SEC	HARDEE POWER STATION	CT2B	HARDEE	NG	DFO	1 /	2033	-71.0	-90.0	-70.0	-89.0	GT	-70	-62	0	27	CE
SEC	HARDEE POWER STATION	ST1	HARDEE	WH	---	1 /	2033	-76.0	-91.0	-76.0	-91.0	CA	-76	-91	0	0	CE
	2034																
	No Entries																

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.1 - SOLAR
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2025 THROUGH DECEMBER 31, 2034

(1)	(2)	(3)	(6) (7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
			COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT		NET CAPABILITY - MW			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
								FIRM		UNCOMMITTED - MW		
UTIL	FACILITY NAME	UNIT NO.	MO. / YEAR	NAMEPLATE CAPABILITY - MW SUM	SUM	WIN	TYPE	SUM	WIN	SUM	WIN	STATUS
	2025											
	SOLAR DEGREDATION				-0.2	0.0		-0.2	0	0	0	
	2026											
JEA	Caldwell Solar	1	12 / 2026		0.0	0.0	PV	14.9	0	0	0	NC
JEA	Miller Solar	1	12 / 2026		0.0	0.0	PV	14.9	0	0	0	NC
JEA	FOREST TRAIL SOLAR	1	12 / 2026		0.0	0.0	PV	10	0	0	0	NC
	SOLAR DEGREDATION				-0.3	0.0		-0.3	0	0	0	
	2027											
LAK	EDGE SOLAR	N/A	3 / 2027	74.8	74.8	74.8	PV	37.4	0	74.8	74.8	C
	SOLAR DEGREDATION				-0.3	0.0		-0.3	0	0	0	
	2028											
JEA	74.9 Solar PPA	1	1 / 2028		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	2	1 / 2028		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	3	4 / 2028		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	4	4 / 2028		0.0	0.0	PV	14.9	0	0	0	NC
DEF	SOLAR QF	4	6 / 2028	75.0	0.0	0.0	PV	0	0	0	0	NC
	SOLAR DEGREDATION				-0.9	0.0		-0.9	0	0	0	
	2029											
	SOLAR DEGREDATION				-1.7	0.0		-1.7	0	0	0	
	2030											
DEF	SOLAR QF	5	6 / 2030	75.0	0.0	0.0	PV	0	0	0	0	NC
JEA	74.9 Solar PPA	5	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	6	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	7	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	8	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.1 - SOLAR
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2025 THROUGH DECEMBER 31, 2034

(1)	(2)	(3)	(6) (7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
			COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN CONTRACT	NAMEPLATE	NET			POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				
		UNIT			CAPABILITY - MW			FIRM		UNCOMMITTED - MW		
UTIL	FACILITY NAME	NO.	MO. / YEAR	SUM	SUM	WIN	TYPE	SUM	WIN	SUM	WIN	STATUS
JEA	74.9 Solar PPA	9	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	10	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	11	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	74.9 Solar PPA	12	12 / 2030		0.0	0.0	PV	14.9	0	0	0	NC
JEA	30 Solar PPA	1	12 / 2030		0.0	0.0	PV	6	0	0	0	NC
	SOLAR DEGREDATION				-1.5	0.0		-1.5	0	0	0	
	2031											
	SOLAR DEGREDATION				-1.7	0.0		-1.7	0	0	0	
	2032											
DEF	SOLAR QF	6	6 / 2032	75.0	0.0	0.0	PV	0	0	0	0	NC
	SOLAR DEGREDATION				-3.3	0.0		-3.3	0	0	0	
	2033											
	SOLAR DEGREDATION				-3.4	0.0		-3.4	0	0	0	
	2034											
	SOLAR DEGREDATION				-3.4			-3.1	0	0	0	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

NON-UTILITY GENERATING FACILITIES SUMMARY

SUMMER			WINTER		
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED QF GENERATION (MW)	YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED QF GENERATION (MW)
2025	648.7	81.5	2025/26	429.5	136.6
2026	544.5	81.4	2026/27	391.0	205.4
2027	583.0	150.1	2027/28	391.0	205.4
2028	641.8	150.0	2028/29	391.0	205.4
2029	640.2	149.9	2029/30	391.0	205.4
2030	638.8	149.8	2030/31	391.0	205.4
2031	762.4	149.7	2031/32	391.0	205.4
2032	759.2	149.6	2032/33	0.0	259.4
2033	395.9	149.5	2033/34	0.0	259.4
2034	392.8	149.5	2034/35	0.0	259.4

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
ALACHUA	FMPA	08/14/83	01/01/99	0.4	0.4	NUC	ST	Entitlement Share of St. Lucie Project (St. Lucie #2)
CFTD	DEF	03/01/16	03/01/31	2.9	0.8	SUN	PV	PV PPA
CFTD	FMPA	01/01/25	12/31/25	133	133	NA	UN	Undetermined Purchase; this is a reserved product.
CFTD	FMPA	01/01/26	12/31/26	108	108	NA	UN	Undetermined Purchase; this is a reserved product.
CFTD	FMPA	01/01/27	12/31/27	109	109	NA	UN	Undetermined Purchase; this is a reserved product.
CFTD	FMPA	01/01/28	12/31/28	110	110	NA	UN	Undetermined Purchase; this is a reserved product.
CFTD	FMPA	01/01/29	12/31/29	112	112	NA	UN	Undetermined Purchase; this is a reserved product.
CFTD	OTH	01/01/19	01/01/36	23.7	13.5	SUN	PV	PV PPA; FL Solar 5 LLC
CFTD	OTH	06/01/23	12/31/42	50.3	23	SUN	PV	PV PPA; Bell Ridge Solar LLC
CFTD	OTH	12/31/25	12/31/44	50.3	23	SUN	PV	PV PPA; Bronson Solar LLC.
DEF	NSG	06/01/12	05/31/27	164.91	176.06	NG	CT	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	164.91	176.06	NG	CT	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	164.91	176.06	NG	CT	Vandolah with present owner (Northern Star Generation)
DEF	NSG	06/01/12	05/31/27	164.91	176.06	NG	CT	Vandolah with present owner (Northern Star Generation)
FKE	FPL	02/17/11	12/31/31	156	122	NG	CT	FKE has entered into a long term full reqirements contract with FPL to purchase power.
FMPA	KUA	01/01/14	12/31/25	248.1	259.3	NG	OT	All KUA owned capacity is used by FMPA to serve the ARP
FMPA	KUA	01/01/26	01/01/99	226.6	237.8	NG	OT	All KUA owned capacity is used by FMPA to serve the ARP - After STN 1 RT
FMPA	Nextera	06/01/25	09/30/25	16.01	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/26	09/30/26	15.96	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/27	09/30/27	15.91	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/28	09/30/28	15.86	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/29	09/30/29	15.82	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/30	09/30/30	15.77	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/31	09/30/31	15.72	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/32	09/30/32	15.67	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/33	09/30/33	15.63	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Nextera	06/01/34	09/30/34	15.58	0	SUN	OT	Firm Solar from Phase I PPA
FMPA	Origis	06/01/25	09/30/25	19.25	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/26	09/30/26	29.99	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/27	09/30/27	29.9	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/28	09/30/28	29.81	0	SUN	OT	Firm Solar from Phase II PPA

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
FMPA	Origis	06/01/29	09/30/29	29.72	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/30	09/30/30	29.63	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/31	09/30/31	29.55	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/32	09/30/32	29.46	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/33	09/30/33	29.37	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	Origis	06/01/34	09/30/34	29.28	0	SUN	OT	Firm Solar from Phase II PPA
FMPA	PowHol	01/01/24	12/31/27	106	106	NG	CT	Oleander 1 PPA early years
FMPA	PowHol	01/01/28	12/31/29	155	155	NG	CT	Oleander 1 PPA later years.
FMPA	SOU	12/16/07	12/16/27	162	180	NG	GT	PPA with SOU (Oleander 5)
FPL	CORONAL	01/01/25	12/31/25	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/25	12/31/25	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/25	12/31/25	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/26	12/31/26	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/26	12/31/26	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/20/26	12/31/26	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/27	12/31/27	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/27	12/31/27	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/27	12/31/27	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/28	12/31/28	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/28	12/31/28	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/28	12/31/28	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/29	12/31/29	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/29	12/31/29	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/29	12/31/29	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/30	12/31/30	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/30	12/31/30	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/30	12/31/30	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/31	12/31/31	30	0	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/31	12/31/31	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/31	12/31/31	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/32	12/31/32	30	30	SUN	PV	GULF COAST SOLAR CENTER I

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
FPL	CORONAL	01/01/32	12/31/32	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/32	12/31/32	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/33	12/31/33	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	CORONAL	01/01/33	12/31/33	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/33	12/31/33	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/34	12/31/34	40	40	SUN	PV	GULF COAST SOLAR CENTER II
FPL	CORONAL	01/01/34	12/31/34	50	50	SUN	PV	GULF COAST SOLAR CENTER III
FPL	CORONAL	01/01/34	12/31/34	30	30	SUN	PV	GULF COAST SOLAR CENTER I
FPL	MSCG	01/01/22	12/31/35	81	109	WND	WT	King Fisher I and II - Purchase from Morgan Stanley Capital Group (MSCG) -GPC CO
FPL	OTH	01/01/12	04/01/32	40	40	MSW	OT	Palm Beach SWA
FPL	OTH	01/01/15	04/01/34	70	70	MSW	OT	Palm Beach SWA- additional
GRU	FIT	01/01/09	12/31/28	0.6	0.6	SUN	PV	Load-reducing 2009 Feed-In Tariff installations
GRU	FIT	01/01/10	12/31/29	2.7	2.7	SUN	PV	Load-reducing 2010 Feed-In Tariff installations
GRU	FIT	01/01/11	12/31/30	6	6	SUN	PV	Load-reducing 2011 Feed-In Tariff installations
GRU	FIT	01/01/12	12/31/31	4.8	4.8	SUN	PV	Load-reducing 2012 Feed-In Tariff installations
GRU	FIT	01/01/13	12/31/32	4.5	4.5	SUN	PV	Load-reducing 2013 Feed-In Tariff installations
HST	FMPA	08/14/83	01/01/99	7	7.3	NUC	ST	Entitlement Share in St. Lucie Project (St. Lucie #2)
HST	FMPA	07/01/87	12/31/25	7.89	7.89	BIT	ST	Entitlement Share in Stanton Project (Stanton 1)
HST	FMPA	07/01/87	12/31/25	5.26	5.26	BIT	ST	Entitlement Share in Tri-City Project (Stanton 1)
HST	FMPA	06/01/96	01/01/99	8.59	8.59	BIT	ST	Entitlement Share in Stanton II Project (Stanton 2)
HST	FMPA	01/01/20	12/31/26	15	15	AB	ST	PPA
HST	FMPA	04/01/23	11/01/43	5	5	SUN	OT	Firm Solar from Phase II PPA
HST	FPL	01/01/20	12/31/25	86	86	OTH	OT	System sale from FPL
HST	MDA	01/01/20	12/31/25	15	15	OTH	OT	TBD
JEA	FMPA	10/31/28	10/31/48	0	0	SUN	PV	
JEA	FMPA	10/31/28	10/31/48	0	0	SUN	PV	
JEA	FPL	01/01/22	01/01/42	200	200	NG	CC	
JEA	FPL	01/01/25	12/31/25	0	0	SUN	PV	
JEA	FPL	01/01/26	12/31/26	0	0	SUN	PV	
JEA	FPL	01/01/27	12/31/27	0	0	SUN	PV	
JEA	FPL	01/01/28	03/31/28	0	0	SUN	PV	

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
LAK	OUC	01/01/25	12/31/25	100	50	NA	UN	Firm Energy and Capacity
LAK	OUC	01/01/26	12/31/26	100	50	NA	UN	Firm Energy and Contract
LAK	Unknown	01/01/27	12/31/27	36	0	NA	UN	Firm Capacity and Energy
LAK	Unknown	01/01/28	12/31/28	41	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/29	12/31/29	51	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/30	12/31/30	56	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/31	12/31/31	66	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/32	12/31/32	76	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/33	12/31/33	86	0	NA	UN	Firm Capacity and Energy Planned
LAK	Unknown	01/01/34	12/31/34	96	0	NA	UN	Firm Capacity and Energy Planned
LWBU	FMPA	08/14/83	01/01/46	21.54	22.4	NUC	ST	Entitlement Share in St. Lucie Project (St. Lucie #2)
LWBU	FMPA	07/01/87	12/31/25	10.74	10.74	BIT	ST	Entitlement Share in Stanton Project (Stanton 1)
LWBU	FMPA	01/01/26	01/01/46	20.72	20.72	SUN	PV	Firm Solar Phase III PPA
LWBU	Origis	08/01/24	12/01/44	13.27	13.27	SUN	OT	Firm Solar from Phase II PPA
LWBU	Origis	06/01/25	12/01/45	20.09	20.09	SUN	OT	Firm Solar from Phase II PPA
LWBU	OUC	01/01/25	12/31/25	50	25	OTH	OT	Represents PR purchase from OUC.
LWBU	TBD	01/01/26	01/01/35	75	50	OTH	OT	POWER PURCHASE AGREEMENT
LWBU	TBD	06/01/28	09/30/34	50	15	OTH	OT	Placeholder for meeting Summer loads plus reserve margin
NSB	FMPA	08/14/83	01/01/99	8.56	8.9	NUC	ST	Entitlement Share in St. Lucie Project (St. Lucie #2)
NSB	FPL	02/01/14	12/31/27	95	95	NA	UNK	Native Load Firm
NSB	TBD	01/01/23	12/31/30	45	45	NA	UN	Future Supply
NSB	TBD	01/01/28	12/31/30	95	95	NA	UNK	Future supply
NSB	TBD	01/01/31	12/31/35	155	155	NA	UN	Future Supply to meet reserve margin
OUC	NEXTERA	01/01/18	12/31/31	342	350	NG	CA	OUC PPA with NextEra Energy Inc. for Stanton A.
OUC	NEXTERA	06/01/20	12/31/40	17	0	SUN	PV	Harmony Solar PPA
OUC	NEXTERA	06/01/20	12/31/40	37.25	0	SUN	PV	Taylor Creek Solar PPA
OUC	Nextera	01/01/24	12/31/28	87	87	NG	CA	OUC PPA with NextEra Energy Inc. for Stanton A
OUC	Nextera	12/18/24	12/18/44	37.25	0	SUN	PV	Harmony 2 Solar PPA
OUC	Nextera	12/18/24	12/18/44	37.25	0	SUN	PV	Storey Bend Solar PPA
OUC	OTH	10/01/13	09/30/34	4	4	LFG	ST	LFG PPA (Port Charlotte)
OUC	OTH	01/01/17	12/31/35	9	9	SUN	PV	Stanton Solar Farm PPA

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
OUC	OTH	01/01/17	12/31/36	6	6	LFG	ST	LFG PPA (Orange County)
OUC	OTH	01/01/19	12/31/34	9	9	LFG	ST	LFG PPA (CBI)
OUC	TBD	06/01/27	05/31/47	100	100	OTH	OT	Future battery energy storage PPA
OUC	TBD	06/01/27	05/31/47	74.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/29	05/31/49	74.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/30	05/31/50	74.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/31	05/31/51	100	100	OTH	OT	Future battery energy storage PPA
OUC	TBD	06/01/31	05/31/51	74.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/32	05/31/52	150	150	OTH	OT	Future battery energy storage PPA
OUC	TBD	06/01/32	05/31/52	74.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/33	05/31/53	186.5	0	SUN	PV	Future Solar PPA
OUC	TBD	06/01/33	05/31/53	250	250	OTH	OT	Future battery energy storage PPA
OUC	TBD	06/01/34	05/31/54	200	200	OTH	OT	Future battery energy storage PPA
OUC	TBD	06/01/34	05/31/54	186.5	0	SUN	PV	Future Solar PPA
SEC	DEF	01/01/25	12/31/26	250	250	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/25	03/31/25	0	600	NG	GT	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/25	12/31/25	100	100	NG	GT	System firm intermediate capacity purchase
SEC	DEF	12/01/25	12/31/25	0	600	NG	GT	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/26	03/31/26	0	525	NG	GT	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/26	12/31/26	200	200	NG	GT	System firm intermediate capacity purchase
SEC	DEF	12/01/26	12/31/26	0	525	NG	GT	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/27	12/31/27	200	200	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/27	03/31/27	0	475	NG	GT	System firm Winter Seasonal Peaking Capacity purchase
SEC	DEF	01/01/27	12/31/30	50	50	NG	GT	System firm intermediate capacity purchase
SEC	DEF	01/01/28	12/31/28	400	400	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/29	12/31/29	350	350	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/30	12/31/30	400	400	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/31	12/31/31	250	250	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/32	12/31/32	350	350	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/33	12/31/33	225	225	NG	GT	System firm peaking capacity purchase
SEC	DEF	01/01/34	12/31/34	350	350	NG	GT	System firm peaking capacity purchase

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
SEC	DEF	01/01/35	12/31/35	400	400	NG	CC	System firm peaking capacity purchase
SEC	HILLS	03/01/10	02/28/25	38	38	MSW	ST	Municipal solid waste facility (Hillsborough Waste to Energy)
SEC	HPP	01/01/13	12/31/32	72	88	NG	CT	Intermediate firm capacity purchase - Hardee CT1A
SEC	HPP	01/01/13	12/31/32	70	89	NG	GT	The firm capacity for Hardee CT2A has been reduced by 27 MW in Winter to reflect current transmission limitations.
SEC	HPP	01/01/13	12/31/32	70	89	NG	GT	The firm capacity for Hardee CT2B has been reduced by 27 MW in Winter to reflect current transmission limitations.
SEC	HPP	01/01/13	12/31/32	72	88	NG	CT	Intermediate firm capacity purchase - Hardee CT1B
SEC	HPP	01/01/13	12/31/32	76	91	WH	CA	Intermediate firm capacity purchase - Hardee ST1
SEC	Nextera	01/01/10	12/31/27	153	182	NG	GT	Firm capacity purchase -Oleander CT3
SEC	Nextera	01/01/10	12/31/27	153	182	NG	GT	Firm capacity purchase -Oleander CT2
SEC	OTH	01/01/14	12/21/55	66	66	DFO	GT	Firm purchase from SECI Members for Diesel Generation (CBGs)
SEC	OTH	12/01/24	11/30/49	74.5	74.5	SUN	PV	Contracted solar facility
SEC	OTH	12/01/24	11/30/49	74.5	74.5	SUN	PV	Contracted solar facility
SEC	OTH	12/01/24	11/30/49	74.5	74.5	SUN	PV	Contracted solar facility
SEC	OTH	12/01/24	11/30/49	74.5	74.5	SUN	PV	Contracted solar facility
SEC	SCS	01/01/23	05/31/26	100	100	BIT	ST	SCS system firm baseload capacity purchase
SEC	Tampa	08/01/11	07/31/26	20	20	MSW	ST	McKay Bay Waste to Energy facility (City of Tampa Waste to Energy)
SEC	TBD	06/01/25	09/30/25	196	0	NG	GT	System firm seasonal purchase
SEC	TBD	12/01/25	03/31/26	0	114	NG	GT	System firm seasonal purchase
SEC	TBD	06/01/26	09/30/26	306	0	NG	GT	System firm seasonal purchase
SEC	TBD	12/01/26	03/31/27	0	6	NG	GT	System firm seasonal purchase
SEC	TBD	06/01/27	09/30/27	4	0	NG	GT	System firm seasonal purchase
SEC	TBD	12/01/27	03/31/28	0	207	NG	GT	System firm seasonal purchase
SEC	TBD	06/01/28	09/30/28	154	0	NG	GT	System firm seasonal purchase
SEC	TBD	12/01/29	03/31/30	0	79	NG	GT	System firm seasonal purchase
SEC	TBD	06/01/30	09/30/30	36	0	NG	GT	System firm seasonal purchase
SEC	TBD	06/01/33	09/30/33	5	0	NG	GT	System firm seasonal purchase
SEC	TBD	12/01/34	03/31/35	0	12	NG	GT	System firm seasonal purchase
STC	FMPA	06/01/96	01/01/46	15.6	15.6	BIT	ST	Entitlement Share in Stanton II Project (Stanton 2)
STC	OUC	10/01/25	09/30/26	269	211	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/26	09/30/27	280	226	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/27	09/30/28	290	235	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 12
SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(10)	(8)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		CONTRACT CAPACITY		PRIMARY FUEL	UNIT TYPE	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)			
STC	OUC	10/01/28	09/30/29	301	253	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/29	09/30/30	307	266	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/30	09/30/31	328	270	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/31	09/30/32	342	278	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/32	09/30/33	357	310	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/33	09/30/34	369	324	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
STC	OUC	10/01/34	09/30/35	381	337	OTH	OT	Interchange between OUC and STC per Interlocal Agreement. Difference between STC peak demand less STC share of Stanton 2.
TEC	FMPA	12/01/24	02/28/25	0	100	NA	CC	Call Option
TEC	Hillsborough WTE	03/01/25	02/28/35	16	16	MSW	OT	Long Term Purchase Power Agreement (Pending Commission Approval)
TEC	OUC	01/01/25	02/28/25	0	150	NA	CC	Call Option
TEC	Pasco WTE	01/01/25	12/31/34	18	18	MSW	OT	Long Term Purchase Power Agreement
TEC	SEC	12/01/24	02/28/25	0	200	NA	CC	Call Option

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.0
FUEL REQUIREMENTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	FUEL REQUIREMENTS		UNITS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	NUCLEAR		TRILLION BTU	312	313	310	312	318	316	317	316	318	316	317
(2)	COAL		1000 TON	4,443	4,208	4,049	3,483	3,044	3,171	3,216	2,827	2,766	2,614	2,308
	RESIDUAL													
(3)		STEAM	1000 BBL	7	0	0	0	0	0	2	9	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL:**	1000 BBL	**7**	**0**	**0**	**0**	**0**	**0**	**2**	**9**	**0**	**0**	**0**
	DISTILLATE													
(7)		STEAM	1000 BBL	75	37	42	35	43	45	39	36	36	30	23
(8)		CC	1000 BBL	55	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	251	209	128	172	91	93	79	27	40	41	36
(10)		**TOTAL:**	1000 BBL	**381**	**246**	**170**	**207**	**134**	**138**	**118**	**63**	**76**	**71**	**59**
	NATURAL GAS													
(11)		STEAM	1000 MCF	89,448	61,685	66,848	63,254	68,805	63,659	61,776	45,690	46,027	47,513	43,061
(12)		CC	1000 MCF	1,298,294	1,227,817	1,225,576	1,224,759	1,213,730	1,203,876	1,179,513	1,157,741	1,127,684	1,128,295	1,099,494
(13)		CT	1000 MCF	51,129	50,743	45,506	38,717	30,050	37,283	38,652	40,594	46,551	40,841	43,779
(14)		**TOTAL:**	1000 MCF	**1,438,871**	**1,340,245**	**1,337,930**	**1,326,730**	**1,312,585**	**1,304,818**	**1,279,941**	**1,244,025**	**1,220,262**	**1,216,649**	**1,186,334**
(15)	OTHER		TRILLION BTU	1,614	4,668	4,536	2,612	1,896	1,731	1,733	1,596	1,663	1,886	2,057

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.1
ENERGY SOURCES (GWH)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	4,270	4,358	4,072	3,876	3,775	3,759	3,649	3,048	3,193	3,150	3,131
(2)	NUCLEAR		GWH	28,967	29,819	29,590	29,696	30,307	30,097	30,190	30,103	30,295	30,089	30,209
(3)	COAL		GWH	9,054	8,798	8,749	7,314	6,686	7,056	7,305	6,106	6,010	5,531	4,985
	RESIDUAL													
(4)		STEAM	GWH	4	0	0	0	0	0	2	6	0	0	0
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL:	GWH	**4**	**0**	**0**	**0**	**0**	**0**	**2**	**6**	**0**	**0**	**0**
	DISTILLATE													
(8)		STEAM	GWH	23	11	15	12	12	11	12	11	11	8	7
(9)		CC	GWH	46	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	106	79	50	70	36	36	27	8	15	14	13
(11)		TOTAL:	GWH	**175**	**90**	**65**	**82**	**48**	**47**	**39**	**19**	**26**	**22**	**20**
	NATURAL GAS													
(12)		STEAM	GWH	7,618	5,714	6,294	5,991	6,373	5,688	5,516	3,927	3,937	4,051	3,661
(13)		CC	GWH	186,257	177,488	177,354	179,033	177,663	176,169	172,067	168,792	164,188	163,017	159,286
(14)		CT	GWH	4,733	5,086	4,481	3,881	2,995	3,730	3,864	4,054	4,646	4,104	4,456
(15)		TOTAL:	GWH	**198,608**	**188,288**	**188,129**	**188,905**	**187,031**	**185,587**	**181,447**	**176,773**	**172,771**	**171,172**	**167,403**
(16)	NUG		GWH	843	825	831	839	848	855	863	871	877	883	889
	RENEWABLES													
(17)		BIOFUELS	GWH	48	36	36	36	36	36	36	36	36	36	36
(18)		BIOMASS	GWH	285	380	443	432	365	274	361	322	426	496	654
(19)		HYDRO	GWH	132	154	154	154	155	154	154	154	155	154	154
(20)		LANDFILL GAS	GWH	203	300	264	124	125	124	124	124	125	124	124
(21)		MSW	GWH	565	500	501	502	503	500	501	501	503	502	501
(22)		SOLAR	GWH	18,708	25,573	29,179	33,627	38,932	44,991	51,794	60,639	68,197	75,424	83,245
(23)		WIND	GWH	1,029	1,031	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031	1,031
(24)		OTHER RENEWABLE	GWH	617	492	0	0	0	0	0	0	0	0	0
(25)		TOTAL:	GWH	**21587**	**28466**	**31608**	**35906**	**41149**	**47110**	**54001**	**62807**	**70475**	**77767**	**85745**
(26)	OTHER		GWH	2113	4013	3145	1724	2021	1985	2627	3886	3970	2811	2566
(27)	NET ENERGY FOR LOAD		GWH	**265621**	**264657**	**266189**	**268342**	**271865**	**276496**	**280123**	**283619**	**287617**	**291425**	**294948**

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 9.2
ENERGY SOURCES (%)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	1.61%	1.65%	1.53%	1.44%	1.39%	1.36%	1.30%	1.07%	1.11%	1.08%	1.06%
(2)	NUCLEAR		%	10.91%	11.27%	11.12%	11.07%	11.15%	10.89%	10.78%	10.61%	10.53%	10.32%	10.24%
(3)	COAL		%	3.41%	3.32%	3.29%	2.73%	2.46%	2.55%	2.61%	2.15%	2.09%	1.90%	1.69%
	RESIDUAL													
(4)		STEAM	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	%	0.01%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	%	0.04%	0.03%	0.02%	0.03%	0.01%	0.01%	0.01%	0.00%	0.01%	0.00%	0.00%
(11)		TOTAL:	%	0.07%	0.03%	0.02%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
	NATURAL GAS													
(12)		STEAM	%	2.87%	2.16%	2.36%	2.23%	2.34%	2.06%	1.97%	1.38%	1.37%	1.39%	1.24%
(13)		CC	%	70.12%	67.06%	66.63%	66.72%	65.35%	63.71%	61.43%	59.51%	57.09%	55.94%	54.00%
(14)		CT	%	1.78%	1.92%	1.68%	1.45%	1.10%	1.35%	1.38%	1.43%	1.62%	1.41%	1.51%
(15)		TOTAL:	%	74.77%	71.14%	70.67%	70.40%	68.80%	67.12%	64.77%	62.33%	60.07%	58.74%	56.76%
(16)	NUG		%	0.32%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.31%	0.30%	0.30%	0.30%
	RENEWABLES													
(17)		BIOFUELS	%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(18)		BIOMASS	%	0.11%	0.14%	0.17%	0.16%	0.13%	0.10%	0.13%	0.11%	0.15%	0.17%	0.22%
(19)		HYDRO	%	0.05%	0.06%	0.06%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%	0.05%
(20)		LANDFILL GAS	%	0.08%	0.11%	0.10%	0.05%	0.05%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%
(21)		MSW	%	0.21%	0.19%	0.19%	0.19%	0.19%	0.18%	0.18%	0.18%	0.17%	0.17%	0.17%
(22)		SOLAR	%	7.04%	9.66%	10.96%	12.53%	14.32%	16.27%	18.49%	21.38%	23.71%	25.88%	28.22%
(23)		WIND	%	0.39%	0.39%	0.39%	0.38%	0.38%	0.37%	0.37%	0.36%	0.36%	0.35%	0.35%
(24)		OTHER RENEWABLE	%	0.23%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		TOTAL	%	8.13%	10.76%	11.87%	13.38%	15.14%	17.04%	19.28%	22.14%	24.50%	26.69%	29.07%
(25)	OTHER		%	0.80%	1.52%	1.18%	0.64%	0.74%	0.72%	0.94%	1.37%	1.38%	0.96%	0.87%
(26)	NET ENERGY FOR LOAD		%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2025

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 13

SUMMARY AND SPECIFICATIONS OF PROPOSED TRANSMISSION LINES

AS OF JANUARY 1, 2025

(1)	(2)		(3)	(4)	(5)	(6)	(7)
LINE OWNERSHIP	TERMINALS		LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE (MO./YR)	NOMINAL VOLTAGE (kV)	CAPACITY (MVA)	SITED UNDER *
DEF	KATHLEEN SUBSTATION	OSPREY SUBSTATION	26	5 / 2025	230	1037	NA
LAK	DRANEFIELD	HAMILTON	5.5	5 / 2025	69	129	NA
DEF	SUNDANCE SUBSTATION	BIRCH SWITCHING STATION	1	7 / 2025	230	919	NA
DEF/SEC	DEF MARTIN WEST	SEC SILVER SPRINGS NORTH	0	12 / 2025	230	1195	NA
DEF	HALF MOON SUBSTATION	CRESCENT SWITCHING STATION	1	1 / 2026	230	919	NA
DEF	RATTLER SUBSTATION	NOBLETON SWITCHING STATION	1	1 / 2026	69	275	NA
DEF	BAILEY MILL SUBSTATION	BAILEY MILL TAP	1	5 / 2026	115	392	NA
DEF	JUMPER CREEK SUBSTATION	CRESCENT SWITCHING STATION	1	6 / 2026	230	919	NA
SEC	SHEC SHADY HILLS COMBINED CYCLE FACILITY	DEF HUDSON NORTH	0.51	11 / 2026	230	1195	NA
DEF	BANNER SUBSTATION	RADIANT SUBSTATION	1	12 / 2026	230	919	NA
DEF	LONESOME CAMP SUBSTATION	Q325 SUBSTATION	1	12 / 2026	230	919	NA
DEF	TURNPIKE SUBSTATION	Q325 SUBSTATION	1	12 / 2026	230	919	NA
DEF	POWERLINE BESS SUBSTATION	POWERLINE SUBSTATION	1	3 / 2027	230	919	NA

* TLSA: Transmission Line Siting Act

* PPSA: Power Plant Siting Act

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

ABBREVIATIONS

ELECTRIC MARKET PARTICIPANTS

CAL	-	Calpine
CFTOD	-	Central Florida Tourism Oversight District
DEF	-	Duke Energy Florida
FKE	-	Florida Keys Electric Cooperative Association, Inc.
FMD	-	Ft. Meade, City of
FMPA	-	Florida Municipal Power Agency
FPL	-	Florida Power & Light
FPU	-	Florida Public Utitlities
FTP	-	Ft. Pierce Utilities Authority
GE	-	General Electric
GaPC	-	Georgia Power Company
GPC	-	Gulf Power Company
GRU	-	Gainesville Regional Utilities
HPP	-	Hardee Power Partners
HST	-	Homestead Energy Services
JEA	-	JEA
KEY	-	Key West, City of
KUA	-	Kissimmee Utility Authority
LAK	-	Lakeland, City of
LCEC	-	Lee County Electric Cooperative
LWBU	-	Lake Worth Beaches, City of
NSB	-	New Smyrna Beach, Utilities Commission of
NSG	-	Northern Star Generation
NRG	-	NRG Energy
OUC	-	Orlando Utilities Commission
OUS	-	Ocala Utility Services
PEC	-	PowerSouth Energy Cooperative
SEC	-	Seminole Electric Cooperative, Inc.
SEPA	-	Southeastern Power Administration
SREC	-	Santa Rosa Energy Center
SOU	-	Southern Power Company
STC	-	St. Cloud, City of
TAL	-	Tallahassee, City of
TEC	-	Tampa Electric Company
VER	-	Vero Beach, City of
WAU	-	Wauchula, City of

OTHER

FRCC	-	Florida Reliability Coordinating Council

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

GENERATION TERMS

Status of Generation Facilities

A	--	Generating unit capability increased
CO	--	Change of ownership (including change of shares of jointly owned units)
D	--	Generating unit capability decreased
D (S)	--	Solar Degradation
EO	--	Non-Firm Generating Capacity (Energy Only). This generation is not included in calculation of Total Available Capacity.
FC	--	Existing generator planned for conversion to another fuel or energy source
IP	--	Planned generator indefinitely postponed or canceled
IR	--	Inactive Reserves. This generation is not included in calculation of Total Available Capacity.
L	--	Regulatory approval pending. Not under construction
M	--	Generating unit put in deactivated shutdown status
NS	--	Merchant Plant - No system impact study, not under construction
OP	--	Operating, available to operate, or on short-term scheduled or forced outage
OP (IR)	--	Generating unit placed into OP status from Inactive Reserves
OP (M)	--	Generating unit placed into OP status following scheduled maintenance
OP (U)	--	Generating unit placed into OP status following scheduled uprate
OS	--	On long-term scheduled or forced outage; not available to operate. This generation is not included in calculation of Total Available Capacity.
OS (IR)	--	Generating unit placed into OS status for Inactive Reserves
OS (M)		Generating unit placed into OS status for scheduled maintenance
OS (RS)	--	Generating unit placed into OS status for reserve shutdown
OS (U)	--	Generating unit placed into OS status for scheduled unit uprate
OT	--	Other
P	--	Planned for installation but not utility-authorized. Not under construction
RA	--	Previously deactivated or retired generator planned for reactivation
RE	--	Retired
RP	--	Proposed for repowering or life extension
RT	--	Existing generator scheduled for retirement
SB	--	Cold Standby: deactivated, in long-term storage and cannot be made available for service in a short period of time. This generation is not included in calculation of Total Available Capacity.
SC	--	Synchronous Condenser
SD	--	Sold to independent power producer
SI	--	Merchant Plant - System impact study completed, not under construction
T	--	Regulatory approval received but not under construction
TS	--	Construction complete, but not yet in commercial operation
U	--	Under construction, less than or equal to 50% complete
V	--	Under construction, more than 50% complete

Ownership

COG	--	Cogenerator
IPP	--	Independent Power Producer
J	--	Utility, joint ownership with one or more other utilities
MER	--	Merchant Generator
SPP	--	Small Power Producing qualifying facility
U	--	Utility, single ownership by respondent

Contracts

C	--	Contract in place
CE	--	Contract Ends
D	--	Decrease in Contract Amount
I	--	Increase in Contract Amount
NC	--	No Contract

Types of Generation Units

BS	--	Battery Storage
CA	--	Combined Cycle Steam Part
CC	--	Combined Cycle Total Unit
CE	--	Compressed Air Energy Storage
CS	--	Combined Cycle Single Shaft
CT	--	Combined Cycle Combustion Turbine Part
FC	--	Fuel Cell
GT	--	Gas Turbine (includes Jet Engine Design)
HY	--	Hydraulic Turbine
IC	--	Internal Combustion Engine
NA	--	Not Available
OT	--	Other
PV	--	Photovoltaic
ST	--	Steam Turbine, including nuclear, and solar steam
WT	--	Wind Turbine

Fuel Transportation Method

CV	--	Conveyor
NA	--	Not Applicable
PL	--	Pipeline
RR	--	Railroad
TK	--	Truck
UN	--	Unknown at this time
WA	--	Water Transportation

Types of Fuel

AB	--	Agriculture Byproducts, Bagasse, Straw, Energy Crops
BAT	--	Battery
BIT	--	Bituminous Coal
DFO	--	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No 2 Fuel Oil, No 4 Fuel Oil)
LFG	--	Landfill Gas
LIG	--	Lignite
MSW	--	Municipal Solid Waste
NA	--	Not Available or Not Applicable
NG	--	Natural Gas
NUC	--	Nuclear
OBG	--	Other BioMass Gases
OBL	--	Other BioMass Liquids
OBS	--	Other BioMass Solids
OG	--	Other Gas
OTH	--	Other
PC	--	Petroleum Coke
RFO	--	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)
SUB	--	Subbituminous Coal
SUN	--	Solar (Photovoltaic, Thermal)
WAT	--	Water
WDS	--	Wood/Wood Waste Solids
WDL	--	Wood/Wood Waste Liquids
WH	--	Waste Heat / Combined Cycle Steam Part
WND	--	Wind

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

CONTRACT TERMS

FR	--	Full Requirement service agreement
PR	--	Partial Requirement service agreement
Schd D	--	Long term firm capacity and energy interchange agreement
Schd E	--	Non-Firm capacity and energy interchange agreement
Schd F	--	Long term non-firm capacity and energy interchange agreement
Schd G	--	Back-up reserve service
Schd J	--	Contract which the terms and conditions are negotiated yearly
UPS	--	Unit Power Sale

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

DEFINITIONS

CAAGR
- Compound Average Annual Growth Rate, usually expressed as a percent.

INTERRUPTIBLE LOAD
- Load which may be disconnected at the supplier's discretion.

LOAD FACTOR
- A percent which is the calculation of NEL / (annual peak demand * the number of hours in the year).

NET CAPABILITY OR NET CAPACITY
- The continous gross capacity, less the power required by all auxillaries associated with the unit.

NET ENERGY FOR LOAD (NEL)
- The net system generation PLUS interchange received MINUS interchange delivered.

PEAK DEMAND OR PEAK LOAD
- The net 60-minute integrated demand, actual or adjusted. Forecasted loads assume normal weather conditions.

PENINSULAR FLORIDA
- Geographically, those Florida utilities located east of the Apalachicola River.

QUALIFYING FACILITY (QF)
- The cogenerator or small power producer which meets FERC criteria for a qualifying facility.

SALES FOR RESALE
- Energy sales to other electric utilities.

STATE OF FLORIDA
- Utilities in Peninsular Florida plus West Florida Electric Cooperative, Choctawhatchee Electric Cooperative, Escambia River Electric Cooperative, Gulf Coast Electric Cooperative, and PowerSouth Energy Cooperative.

SUMMER
- June 1 through August 31 of each year being studied.

WINTER
- December 1 through March 1.

YEAR
- The calendar year, January 1, through December 31. Unless otherwise indicated, this is the year used for historical and forecast data.

STATE OF FLORIDA SUPPLEMENT

TO THE

FLORIDA RELIABILITY COORDINATING COUNCIL

2025

REGIONAL LOAD & RESOURCE PLAN

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND (MW)					WINTER PEAK DEMAND (MW)				ENERGY		
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2015	48,649				2015 / 16	40,448				2015	248,351	58.28%
2016	50,606				2016 / 17	39,046				2016	246,495	55.60%
2017	49,327				2017 / 18	46,127				2017	244,464	56.58%
2018	48,426				2018 / 19	38,516				2018	250,605	59.08%
2019	51,053				2019 / 20	41,018				2019	253,801	56.75%
2020	49,496				2020 / 21	39,842				2020	257,999	59.50%
2021	46,409				2021 / 22	41,295				2021	242,272	59.59%
2022	51,293				2022 / 23	42,377				2022	258,701	57.58%
2023	54,684				2023 / 24	39,046				2023	263,176	54.94%
2024	53,390				2024 / 25	45,710				2024	267,962	57.29%

YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET FIRM PEAK DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
2025	54,514	721	2,624	51,169	2025 / 26	49,243	699	2,428	46,116	2025	267,094	55.93%
2026	55,016	721	2,630	51,665	2026 / 27	49,832	699	2,436	46,697	2026	268,667	55.75%
2027	55,479	721	2,636	52,122	2027 / 28	50,505	699	2,435	47,371	2027	270,852	55.73%
2028	55,929	720	2,637	52,572	2028 / 29	51,400	699	2,433	48,268	2028	274,401	56.01%
2029	56,658	721	2,639	53,298	2029 / 30	52,130	699	2,438	48,993	2029	279,061	56.23%
2030	57,230	721	2,647	53,862	2030 / 31	52,745	699	2,444	49,602	2030	282,713	56.39%
2031	57,983	721	2,658	54,604	2031 / 32	53,462	699	2,448	50,315	2031	286,229	56.35%
2032	58,839	720	2,668	55,451	2032 / 33	54,194	699	2,455	51,040	2032	290,241	56.31%
2033	59,549	721	2,679	56,149	2033 / 34	54,894	699	2,458	51,737	2033	294,068	56.37%
2034	60,304	721	2,691	56,892	2034 / 35	55,449	699	2,465	52,285	2034	297,608	56.34%

NOTE: FORECASTED SUMMER AND WINTER DEMANDS ARE NON-COINCIDENT.

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 4.0
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL										
YEAR	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	GWH	AVERAGE NO. OF CUSTOMERS	AVG. KWH CONSUMPTION PER CUST.	STREET & HIGHWAY LIGHTING GWH	OTHER SALES GWH	TOTAL SALES GWH	WHOLESALE PURCHASES FOR RESALE GWH	WHOLESALE SALES FOR RESALE GWH	UTILITY USE & LOSSES GWH	AGGREGATION ADJUSTMENT GWH	NET ENERGY FOR LOAD GWH
2015	117,738	8,666,064	13,586	85,996	1,077,633	79,801	17,355	22,706	764,335	857	5,736	227,682	0	12,827	12,987	(5,145)	248,351
2016	118,663	8,797,121	13,489	86,268	1,093,241	78,910	17,248	23,154	744,925	848	5,718	228,745	0	13,237	11,480	(6,967)	246,495
2017	116,740	8,914,734	13,095	85,681	1,106,795	77,414	17,329	22,994	753,631	753	5,731	226,234	0	13,218	11,974	(6,962)	244,464
2018	119,980	9,009,348	13,317	86,027	1,112,686	77,315	17,153	22,732	754,575	750	5,932	229,842	0	13,718	12,271	(5,226)	250,605
2019	121,826	9,178,121	13,274	86,781	1,132,143	76,652	17,248	22,702	759,757	725	5,958	232,538	0	14,374	12,395	(5,506)	253,801
2020	127,550	9,336,365	13,662	83,024	1,145,120	72,502	17,036	22,476	757,964	710	5,733	234,053	0	15,532	12,599	(4,185)	257,999
2021	124,654	9,506,701	13,112	84,527	1,160,958	72,808	17,443	22,893	761,936	697	5,804	233,125	0	14,714	12,165	(17,732)	242,272
2022	128,131	9,671,978	13,248	87,137	1,178,083	73,965	17,897	24,045	744,313	700	5,987	239,852	0	16,604	11,351	(9,106)	258,701
2023	129,842	9,831,873	13,206	88,242	1,184,475	74,499	17,613	25,578	688,600	669	6,002	242,368	0	14,544	12,131	(5,867)	263,176
2024	132,086	10,056,332	13,135	89,514	1,202,198	74,459	17,787	25,131	707,771	686	5,950	246,023	0	14,666	13,028	(5,755)	267,962
2015-2024 % AAGR	**1.29%**			**0.45%**			**0.27%**										**0.85%**
2025	130,301	10,201,797	12,772	89,419	1,219,958	73,297	17,713	25,776	687,190	683	5,908	244,024	0	14,125	13,716	(4,771)	267,094
2026	131,373	10,356,887	12,685	90,201	1,236,577	72,944	18,028	25,795	698,895	644	5,907	246,153	0	14,291	13,323	(5,100)	268,667
2027	132,606	10,504,012	12,624	90,727	1,252,314	72,447	18,162	25,874	701,940	623	5,942	248,060	0	14,186	13,632	(5,026)	270,852
2028	134,172	10,650,579	12,598	91,441	1,267,518	72,142	19,573	26,029	751,969	614	5,951	251,751	0	13,674	14,036	(5,060)	274,401
2029	135,986	10,793,688	12,599	92,891	1,281,407	72,491	20,959	26,234	798,925	608	5,970	256,414	0	13,431	14,025	(4,809)	279,061
2030	137,836	10,934,672	12,605	93,923	1,296,969	72,417	22,391	26,421	847,470	608	5,984	260,742	0	12,619	14,201	(4,849)	282,713
2031	139,894	11,073,840	12,633	95,119	1,311,045	72,552	23,010	26,540	866,993	607	5,996	264,626	0	11,026	14,274	(3,697)	286,229
2032	142,097	11,211,021	12,675	95,740	1,324,883	72,263	23,609	26,563	888,793	608	5,985	268,039	0	11,061	14,890	(3,749)	290,241
2033	144,748	11,346,355	12,757	96,592	1,338,491	72,165	24,233	26,473	915,385	608	6,032	272,213	0	11,153	14,503	(3,801)	294,068
2034	147,179	11,479,407	12,821	97,278	1,351,856	71,959	24,310	26,291	924,651	609	6,039	275,415	0	11,242	14,805	(3,854)	297,608
2025-2034 % AAGR	**1.36%**			**0.94%**			**3.58%**										**1.21%**

6/11/2025
1:50 PM

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 5.0
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
	SUMMER NET FIRM PEAK	DEMAND REDUCTION				CUMULATIVE CONSERVATION		SUMMER TOTAL
YEAR	DEMAND	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2023	54,684	0	864	957	118	2,655	1,842	61,120
2024	53,390	0	926	984	187	2,685	1,860	60,032
2025	51,169	721	1,384	1,240	285	2,764	1,887	59,450
2026	51,665	721	1,380	1,250	340	2,824	1,908	60,088
2027	52,122	721	1,375	1,261	340	2,888	1,928	60,635
2028	52,572	720	1,368	1,269	340	2,950	1,949	61,168
2029	53,298	721	1,363	1,276	340	3,013	1,972	61,983
2030	53,862	721	1,363	1,284	340	3,075	1,994	62,639
2031	54,604	721	1,366	1,292	340	3,136	2,015	63,474
2032	55,451	720	1,367	1,301	340	3,196	2,035	64,410
2033	56,149	721	1,370	1,309	340	3,256	2,055	65,200
2034	56,892	721	1,372	1,319	340	3,317	2,074	66,035
CAAGR (%):	**1.18%**							

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 6.0
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]

	WINTER	DEMAND REDUCTION						
	NET FIRM		RESIDENTIAL	COMM./IND.		CUMULATIVE		WINTER
	PEAK	INTERRUPTIBLE	LOAD	LOAD	SELF-SERVED	CONSERVATION		TOTAL
YEAR	DEMAND	LOAD	MANAGEMENT	MANAGEMENT	GENERATION	RESIDENTIAL	COMM./IND.	DEMAND
2023/24	39,046	25	71	34	210	2,970	1,032	43,388
2024/25	45,710	285	66	127	402	2,999	1046.3	50,635
2025/26	46,116	699	1,485	943	458	3,079	1,068	53,848
2026/27	46,697	699	1,484	952	459	3,144	1,083	54,518
2027/28	47,371	699	1,475	960	460	3,201	1,093	55,259
2028/29	48,268	699	1,466	967	461	3,277	1,109	56,247
2029/30	48,993	699	1,464	974	462	3,333	1,119	57,044
2030/31	49,602	699	1,463	981	462	3,403	1,135	57,745
2031/32	50,315	699	1,460	988	462	3,472	1,150	58,546
2032/33	51,040	699	1,459	996	463	3,519	1,160	59,336
2033/34	51,737	699	1,456	1,002	464	3,591	1,176	60,125
2034/35	52,285	699	1,456	1,009	465	3,668	1,192	60,774
CAAGR (%):	**1.40%**							

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 7.0
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWH)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								[(2)+(3)+(4)+(5)+(6)+(7)+(8)]
		ENERGY REDUCTION						
YEAR	NET ENERGY FOR LOAD	INTERRUPTIBLE LOAD	RESIDENTIAL LOAD MANAGEMENT	COMM./IND. LOAD MANAGEMENT	SELF-SERVED GENERATION	CUMULATIVE CONSERVATION RESIDENTIAL	CUMULATIVE CONSERVATION COMM./IND.	TOTAL ENERGY FOR LOAD
2023	263,176	0	0	0	1,352	6,120	4,923	275,571
2024	267,962	0	0	0	1,252	6,207	5,024	280,445
2025	267,094	0	0	11	1,488	6,370	5,126	280,090
2026	268,667	0	0	11	1,885	6,587	5,309	282,459
2027	270,852	0	0	11	1,885	6,858	5,542	285,148
2028	274,401	0	0	11	1,886	7,176	5,830	289,305
2029	279,061	0	0	11	1,885	7,540	6,174	294,672
2030	282,713	0	0	11	1,885	7,953	6,574	299,136
2031	286,229	0	0	11	1,885	8,414	7,031	303,570
2032	290,241	0	0	11	1,886	8,923	7,547	308,608
2033	294,068	0	0	11	1,885	9,481	8,120	313,566
2034	297,608	0	0	11	1,885	10,085	8,753	318,342
CAAGR (%):	**1.21%**							

2025

LOAD AND RESOURCE PLAN

STATE OF FLORIDA

SUMMARY OF INTERRUPTIBLE LOAD AND LOAD MANAGEMENT - MW

2025 THROUGH 2034

SUMMER

YEAR	FRCC TOTALS			STATE TOTALS			STATE TOTAL INT + LM
	INT	RES LM	COM LM	INT	RES LM	COM LM	
2025	721	1,384	1,240	721	1,384	1,240	3,345
2026	721	1,380	1,250	721	1,380	1,250	3,351
2027	721	1,375	1,261	721	1,375	1,261	3,357
2028	720	1,368	1,269	720	1,368	1,269	3,357
2029	721	1,363	1,276	721	1,363	1,276	3,360
2030	721	1,363	1,284	721	1,363	1,284	3,368
2031	721	1,366	1,292	721	1,366	1,292	3,379
2032	720	1,367	1,301	720	1,367	1,301	3,388
2033	721	1,370	1,309	721	1,370	1,309	3,400
2034	721	1,372	1,319	721	1,372	1,319	3,412

WINTER

YEAR	FRCC TOTALS			STATE TOTALS			STATE TOTAL INT + LM
	INT	RES LM	COM LM	INT	RES LM	COM LM	
2025/26	699	1,485	943	699	1,485	943	3,127
2026/27	699	1,484	952	699	1,484	952	3,135
2027/28	699	1,475	960	699	1,475	960	3,134
2028/29	699	1,466	967	699	1,466	967	3,132
2029/30	699	1,464	974	699	1,464	974	3,137
2030/31	699	1,463	981	699	1,463	981	3,143
2031/32	699	1,460	988	699	1,460	988	3,147
2032/33	699	1,459	996	699	1,459	996	3,154
2033/34	699	1,456	1,002	699	1,456	1,002	3,157
2034/35	699	1,456	1,009	699	1,456	1,009	3,164

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 2025

	NET CAPABILITY - MW	
UTILITY	**SUMMER**	**WINTER**
POWERSOUTH ENERGY COOPERATIVE	1,990	2,242
TOTALS:		
FRCC REGION:	58,684	57,624
STATE OF FLORIDA:	60,674	59,866
FRCC NON-UTILITY GENERATING FACILITIES(FIRM):	2,784	2,619
TOTAL STATE NON-UTILITY GENERATING FACILITIES:	2,784	2,619
TOTAL FRCC Region:	**61,468**	**60,243**
TOTAL STATE OF FLORIDA:	**63,458**	**62,485**

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.0
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (11)	(12)	(13)		(14)	(15)	(16)
				PRIMARY FUEL		ALTERNATE FUEL		ALT. FUEL STORAGE (DAYS	COM'L IN-SERVICE	EXPECTED RETIREMENT	GROSS CAPABILITY - MW		NET CAPABILITY - MW		
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	BURN)	MO. / YEAR	MO. / YEAR	SUMMER (MW)	WINTER (MW)	SUMMER (MW)	WINTER (MW)	STATUS
POWERSOUTH ENERGY COOPERATIVE															
GANTT	3	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1926	--- / ---	0.8	0.8	0.8	0.8	OP
GANTT	4	COVINGTON, AL	HY	WAT	WA	---	---	0	2 / 1945	--- / ---	1.8	1.8	1.8	1.8	OP
JAMES H. MILLER JR. (*)	2	JEFFERSON, AL	ST	BIT	WA	---	---	0	6 / 1985	--- / ---	57	57	57	57	OP
JAMES H. MILLER JR. (*)	1	JEFFERSON, AL	ST	BIT	WA	---	---	0	6 / 1978	--- / ---	57	57	57	57	OP
Lowman Energy Center	1	WASHINGTON AL	CT	NG	PL	---	---	0	9 / 2023	--- / ---	380	421	380	421	OP
Lowman Energy Center	2	WASHINGTON AL	CA	NG	PL	---	---	0	9 / 2023	--- / ---	259	266	259	266	OP
MCINTOSH	4	WASHINGTON, AL	CT	NG	PL	NA	UN	0	12 / 2010	--- / ---	169	214	169	214	OP
MCINTOSH	5	WASHINGTON, AL	CT	NG	PL	---	---	0	12 / 2010	--- / ---	166	211	166	211	OP
MCINTOSH	2	WASHINGTON, AL	GT	NG	PL	DFO	TK	0	6 / 1998	--- / ---	110	120	110	120	OP
MCINTOSH	1	WASHINGTON, AL	CE	NG	PL	---	---	0	6 / 1991	--- / ---	25	25	25	25	OP
MCINTOSH	3	WASHINGTON, AL	GT	NG	PL	DFO	TK	0	6 / 1998	--- / ---	110	120	110	120	OP
MCWILLIAMS	VAN1	COVINGTON, AL	CT	NG	PL	---	---	0	1 / 2002	--- / ---	168	203	168	203	OP
MCWILLIAMS	1	COVINGTON, AL	CA	WH	NA	---	---	0	12 / 1954	--- / ---	8	8	8	8	OP
MCWILLIAMS	3	COVINGTON, AL	CA	WH	NA	---	---	0	8 / 1959	--- / ---	15	15	15	15	OP
MCWILLIAMS	4	COVINGTON, AL	GT	NG	PL	DFO	TK	0	12 / 1996	--- / ---	109	121	109	121	OP
MCWILLIAMS	VAN3	COVINGTON, AL	CA	WH	NA	---	---	0	1 / 2002	--- / ---	174	186	174	186	OP
MCWILLIAMS	VAN2	COVINGTON, AL	CT	NG	PL	---	---	0	1 / 2002	--- / ---	168	203	168	203	OP
MCWILLIAMS	2	COVINGTON, AL	CA	WH	NA	---	---	0	12 / 1954	--- / ---	8	8	8	8	OP
POINT A	1	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1945	--- / ---	1.4	1.4	1.4	1.4	OP
POINT A	2	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1925	--- / ---	1.4	1.4	1.4	1.4	OP
POINT A	3	COVINGTON, AL	HY	WAT	WA	---	---	0	1 / 1949	--- / ---	1.6	1.6	1.6	1.6	OP
											PEC TOTAL:		**1,990**	**2,242**	
										FRCC TOTAL:			**58,684**	**57,624**	
										STATE TOTAL:			**60,674**	**59,866**	

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 1.1
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
(JANUARY 1, 2025 THROUGH DECEMBER 31, 2034)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY FUEL TYPE	PRIMARY FUEL TRANS.	ALTERNATE FUEL TYPE	ALTERNATE FUEL TRANS.	ALT. FUEL STORAGE (DAYS BURN)	COMMERICAL IN-SERVICE MO. / YEAR	GROSS CAPABILITY (MW) SUMMER (MW)	GROSS CAPABILITY (MW) WINTER (MW)	NET CAPABILITY (MW) SUMMER (MW)	NET CAPABILITY (MW) WINTER (MW)	STATUS
	2025 - 2024 No Entries														
										FRCC FUTURE TOTAL:			9,727	12,511	
										STATE FUTURE TOTAL:			9,727	12,511	

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 10
SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.		NET FIRM PEAK	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSIDE REGION (MW)	OUTSIDE REGION (MW)	REGIONAL IMPORTS (MW)	REGIONAL EXPORTS (MW)	NON-UTILITY PURCHASES (MW)	AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	DEMAND (MW)	(MW)	% OF PEAK
2025	61,799	0	381	0	2,877	65,057	54,514	10,543	19%	51,169	13,888	27%
2026	63,409	0	281	0	2,798	66,488	55,016	11,472	21%	51,665	14,823	29%
2027	64,382	0	281	0	2,197	66,860	55,479	11,381	21%	52,122	14,738	28%
2028	65,021	0	281	0	1,837	67,139	55,929	11,210	20%	52,572	14,567	28%
2029	66,129	0	281	0	1,747	68,157	56,658	11,499	20%	53,298	14,859	28%
2030	66,511	0	281	0	1,591	68,383	57,230	11,153	19%	53,862	14,521	27%
2031	67,713	0	281	0	1,714	69,709	57,983	11,726	20%	54,604	15,105	28%
2032	68,397	0	281	0	1,328	70,006	58,839	11,167	19%	55,451	14,555	26%
2033	70,101	0	281	0	965	71,347	59,549	11,798	20%	56,149	15,198	27%
2034	69,411	0	281	0	892	70,584	60,304	10,280	17%	56,892	13,692	24%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INSTALLED CAPACITY		FIRM INTERCHANGE		FIRM	TOTAL		RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.		NET FIRM PEAK	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSIDE REGION (MW)	OUTSIDE REGION (MW)	REGIONAL IMPORTS (MW)	REGIONAL EXPORTS (MW)	NON-UTILITY PURCHASES (MW)	AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	DEMAND (MW)	(MW)	% OF PEAK
2025 / 26	62,358	0	409	0	2,543	65,310	49,243	16,067	33%	46,116	19,194	42%
2026 / 27	63,740	0	309	0	2,504	66,554	49,832	16,722	34%	46,697	19,857	43%
2027 / 28	64,634	0	309	0	1,305	66,248	50,505	15,743	31%	47,371	18,877	40%
2028 / 29	65,788	0	309	0	1,218	67,314	51,400	15,914	31%	48,268	19,046	39%
2029 / 30	66,555	0	309	0	1,063	67,927	52,130	15,797	30%	48,993	18,934	39%
2030 / 31	68,102	0	309	0	1,063	69,474	52,745	16,729	32%	49,602	19,872	40%
2031 / 32	68,647	0	309	0	713	69,669	53,462	16,207	30%	50,315	19,354	38%
2032 / 33	70,567	0	309	0	282	71,158	54,194	16,964	31%	51,040	20,118	39%
2033 / 34	72,455	0	309	0	282	73,046	54,894	18,152	33%	51,737	21,309	41%
2034 / 35	70,899	0	309	0	165	71,372	55,449	15,923	29%	52,285	19,087	37%

NOTE - COLUMN 11: NET FIRM PEAK DEMAND = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 3.0
EXISTING NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
				POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				GROSS		NET						
				FIRM		UNCOMMITTED - MW		CAPABILITY - MW		CAPABILITY - MW					COM'L IN-	
		UNIT		SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	UNIT	FUEL TYPE		SERVICE	
UTILITY	FACILITY NAME	NO.	LOCATION	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	TYPE	PRI	ALT	MO. / YEAR	STATUS
			FRCC REGION TOTAL:	686.9	571.5	81.5	136.6	(UNCOMMITTED TOTAL EXCLUDES MERCHANT FACILITIES)								
			STATE TOTAL:	686.9	571.5	81.5	136.6									

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
FRCC Form 3.1
PLANNED AND PROSPECTIVE NON-UTILITY, QF, AND SELF SERVICE GENERATION FACILITIES
INSTALLATIONS, CHANGES, AND REMOVALS
JANUARY 1, 2025 THROUGH DECEMBER 31, 2034

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
				POTENTIAL EXPORT TO GRID AT TIME OF PEAK (MW)				GROSS		NET					COMMERCIAL IN-SERVICE/ RETIREMENT/ OR CHANGE IN	
		UNIT		FIRM		UNCOMMITTED - MW		CAPABILITY - MW		CAPABILITY - MW			FUEL TYPE		CONTRACT	
UTIL	FACILITY NAME	NO.	LOCATION	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	TYPE	PRI.	ALT.	MO. / YEAR	STATUS
	2025 - 2034 No Entries															

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA
NON-UTILITY GENERATING FACILITIES SUMMARY

	SUMMER			WINTER	
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED QF GENERATION (MW)	YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED QF GENERATION (MW)
2025	648.7	81.5	2025/26	429.5	136.6
2026	544.5	81.4	2026/27	391.0	205.4
2027	583.0	150.1	2027/28	391.0	205.4
2028	641.8	150.0	2028/29	391.0	205.4
2029	640.2	149.9	2029/30	391.0	205.4
2030	638.8	149.8	2030/31	391.0	205.4
2031	762.4	149.7	2031/32	391.0	205.4
2032	759.2	149.6	2032/33	0.0	259.4
2033	395.9	149.5	2033/34	0.0	259.4
2034	392.8	149.5	2034/35	0.0	259.4

2025

LOAD AND RESOURCE PLAN

STATE OF FLORIDA

FRCC Form 12

SUMMARY OF FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PURCHASING ENTITY	SELLING ENTITY	CONTRACT TERM		NET CAPABILITY - MW		SUMMER FIRM	WINTER FIRM	PRIMARY FUEL	DESCRIPTION
		FROM (MM/DD/YY)	TO (MM/DD/YY)	SUMMER (MW)	WINTER (MW)				
PEC	Origis	12/31/22	12/31/42	80	80	0	0	NA	

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.0
FUEL REQUIREMENTS
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FUEL REQUIREMENTS		UNITS	ACTUAL 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	NUCLEAR		TRILLION BTU	312	313	310	312	318	316	317	316	318	316	317
(2)	COAL		1000 TON	4,443	4,208	4,049	3,483	3,044	3,171	3,216	2,827	2,766	2,614	2,308
	RESIDUAL													
(3)		STEAM	1000 BBL	7	0	0	0	0	0	2	9	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL:**	1000 BBL	**7**	**0**	**0**	**0**	**0**	**0**	**2**	**9**	**0**	**0**	**0**
	DISTILLATE													
(7)		STEAM	1000 BBL	75	37	42	35	43	45	39	36	36	30	23
(8)		CC	1000 BBL	55	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	251	209	128	172	91	93	79	27	40	41	36
(10)		**TOTAL:**	1000 BBL	**381**	**246**	**170**	**207**	**134**	**138**	**118**	**63**	**76**	**71**	**59**
	NATURAL GAS													
(11)		STEAM	1000 MCF	89,448	61,685	66,848	63,254	68,805	63,659	61,776	45,690	46,027	47,513	43,061
(12)		CC	1000 MCF	1,310,300	1,238,849	1,235,779	1,236,163	1,225,548	1,214,504	1,189,860	1,168,336	1,138,541	1,138,945	1,109,949
(13)		CT	1000 MCF	51,831	50,802	45,578	38,783	30,093	37,306	38,675	40,609	46,563	40,842	43,801
(14)		**TOTAL:**	1000 MCF	**1,451,579**	**1,351,336**	**1,348,205**	**1,338,200**	**1,324,446**	**1,315,469**	**1,290,311**	**1,254,635**	**1,231,131**	**1,227,300**	**1,196,811**
(15)	OTHER		TRILLION BTU	1,614	4,668	4,536	2,612	1,896	1,731	1,733	1,596	1,663	1,886	2,057

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.1
ENERGY SOURCES (GWH)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		**UNITS**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
(1)	**ANNUAL FIRM INTER-REGION INTERCHANGE**		**GWH**	4,578	4,915	4,701	4,343	4,243	4,488	4,416	3,780	3,867	3,877	3,876
(2)	**NUCLEAR**		**GWH**	28,967	29,819	29,590	29,696	30,307	30,097	30,190	30,103	30,295	30,089	30,209
(3)	**COAL**		**GWH**	9,054	8,798	8,749	7,314	6,686	7,056	7,305	6,106	6,010	5,531	4,985
	RESIDUAL													
(4)		**STEAM**	**GWH**	4	0	0	0	0	0	2	6	0	0	0
(5)		**CC**	**GWH**	0	0	0	0	0	0	0	0	0	0	0
(6)		**CT**	**GWH**	0	0	0	0	0	0	0	0	0	0	0
(7)		**TOTAL:**	**GWH**	**4**	**0**	**0**	**0**	**0**	**0**	**2**	**6**	**0**	**0**	**0**
	DISTILLATE													
(8)		**STEAM**	**GWH**	23	11	15	12	12	11	12	11	11	8	7
(9)		**CC**	**GWH**	46	0	0	0	0	0	0	0	0	0	0
(10)		**CT**	**GWH**	106	79	50	70	36	36	27	8	15	14	13
(11)		**TOTAL:**	**GWH**	**175**	**90**	**65**	**82**	**48**	**47**	**39**	**19**	**26**	**22**	**20**
	NATURAL GAS													
(12)		**STEAM**	**GWH**	7,618	5,714	6,294	5,991	6,373	5,688	5,516	3,927	3,937	4,051	3,661
(13)		**CC**	**GWH**	188,026	179,141	178,896	180,726	179,412	177,762	173,620	170,386	165,821	164,621	160,859
(14)		**CT**	**GWH**	4,796	5,091	4,487	3,887	2,999	3,733	3,867	4,057	4,648	4,107	4,460
(15)		**TOTAL:**	**GWH**	**200,440**	**189,946**	**189,677**	**190,604**	**188,784**	**187,183**	**183,003**	**178,370**	**174,406**	**172,779**	**168,980**
(16)	**NUG**		**GWH**	843	825	831	839	848	855	863	871	877	883	889
	RENEWABLES													
(17)		**BIOFUELS**	**GWH**	48	36	36	36	36	36	36	36	36	36	36
(18)		**BIOMASS**	**GWH**	285	380	443	432	365	274	361	322	426	496	654
(19)		**GEOTHERMAL**	**GWH**	0	0	0	0	0	0	0	0	0	0	0
(20)		**HYDRO**	**GWH**	137	159	159	159	160	159	159	159	160	159	159
(21)		**LANDFILL GAS**	**GWH**	212	303	268	126	126	125	125	125	126	125	125
(22)		**MSW**	**GWH**	565	500	501	502	503	500	501	501	503	502	501
(23)		**SOLAR**	**GWH**	18,708	25,617	29,270	33,765	39,070	45,123	51,929	60,772	68,331	75,559	83,381
(24)		**WIND**	**GWH**	1,029	1,031	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031	1,031
(25)		**OTHER RENEWABLE**	**GWH**	617	492	0	0	0	0	0	0	0	0	0
		TOTAL	**GWH**	**21,601**	**28,518**	**31,708**	**36,051**	**41,293**	**47,248**	**54,142**	**62,946**	**70,615**	**77,908**	**85,887**
(26)	**OTHER**			8049	8924	8450	6949	7254	6898	7605	7726	7895	6781	6618
(27)	**NET ENERGY FOR LOAD**			**273711**	**271835**	**273771**	**275878**	**279463**	**283872**	**287565**	**289927**	**293991**	**297870**	**301464**

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 9.2
ENERGY SOURCES (%)
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	1.67%	1.81%	1.72%	1.57%	1.52%	1.58%	1.54%	1.30%	1.32%	1.30%	1.29%
(2)	NUCLEAR		%	10.58%	10.97%	10.81%	10.76%	10.84%	10.60%	10.50%	10.38%	10.30%	10.10%	10.02%
(3)	COAL		%	3.31%	3.24%	3.20%	2.65%	2.39%	2.49%	2.54%	2.11%	2.04%	1.86%	1.65%
	RESIDUAL													
(4)		STEAM	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	%	0.01%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	%	0.04%	0.03%	0.02%	0.03%	0.01%	0.01%	0.01%	0.00%	0.01%	0.00%	0.00%
(11)		TOTAL:	%	0.06%	0.03%	0.02%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
	NATURAL GAS													
(12)		STEAM	%	2.78%	2.10%	2.30%	2.17%	2.28%	2.00%	1.92%	1.35%	1.34%	1.36%	1.21%
(13)		CC	%	68.70%	65.90%	65.35%	65.51%	64.20%	62.62%	60.38%	58.77%	56.40%	55.27%	53.36%
(14)		CT	%	1.75%	1.87%	1.64%	1.41%	1.07%	1.32%	1.34%	1.40%	1.58%	1.38%	1.48%
(15)		TOTAL:	%	73.23%	69.88%	69.28%	69.09%	67.55%	65.94%	63.64%	61.52%	59.32%	58.00%	56.05%
(16)	NUG		%	0.31%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.29%
	RENEWABLES													
(17)		BIOFUELS	%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
(18)		BIOMASS	%	0.10%	0.14%	0.16%	0.16%	0.13%	0.10%	0.13%	0.11%	0.14%	0.17%	0.22%
(19)		GEOTHERMAL	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(20)		HYDRO	%	0.05%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%
(21)		LANDFILL GAS	%	0.08%	0.11%	0.10%	0.05%	0.05%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%
(22)		MSW	%	0.21%	0.18%	0.18%	0.18%	0.18%	0.18%	0.17%	0.17%	0.17%	0.17%	0.17%
(23)		SOLAR	%	6.83%	9.42%	10.69%	12.24%	13.98%	15.90%	18.06%	20.96%	23.24%	25.37%	27.66%
(24)		WIND	%	0.38%	0.38%	0.38%	0.37%	0.37%	0.36%	0.36%	0.36%	0.35%	0.35%	0.34%
(25)		OTHER RENEWABLE	%	0.23%	0.18%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		TOTAL	%	7.89%	10.49%	11.58%	13.07%	14.78%	16.64%	18.83%	21.71%	24.02%	26.16%	28.49%
(26)	OTHER (SPECIFY)		%	2.94%	3.28%	3.09%	2.52%	2.60%	2.43%	2.64%	2.66%	2.69%	2.28%	2.20%
(27)	NET ENERGY FOR LOAD		%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

2025
LOAD AND RESOURCE PLAN
STATE OF FLORIDA

FRCC Form 13
SUMMARY AND SPECIFICATIONS OF PROPOSED TRANSMISSION LINES
AS OF JANUARY 1, 2025

(1)	(2)		(3)	(4)	(5)	(6)	(7)
LINE OWNERSHIP	TERMINALS		LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE DATE(MO/YR)	NOMINAL VOLTAGE (kV)	CAPACITY (MVA)	SITED UNDER
PEC	Graceville	Holmes Creek	1	6 / 2025	115	210	NA
PEC	WALLACE JCT	ALLENTOWN	0	6 / 2025	115	210	NA
PEC	ALLENTOWN	WYE	0	7 / 2025	115	120	NA
PEC	Southport	Highpoint	7.3	12 / 2026	115	217	NA
PEC	Gaskin	Highpoint	0	9 / 2027	115	217	NA

MERCHANT GENERATION IN FLORIDA

MERCHANT GENERATION IN FLORIDA

FRCC has included information on merchant generation facilities for the following companies to include in the 2025 Regional Load & Resource Plan:

1. NextEra Energy Resources (NEER)
2. Santa Rosa Energy Center (SREC)
3. Northern Star Generation (NSG)
4. Origis Energy

CODES USED IN FORMS FOR MERCHANT GENERATING FACILITIES

Unit Status	Contract Status	Ownership
NS – Merchant plant –No system impact study, not under construction	**C –** Contract in place	**MER –** Merchant Generator
SI – Merchant plant – System impact study completed, not under construction	**CC –** Contract Change	
U – Under construction, less than or equal to 50% complete	**NC –** No Contract	
V – Under construction, more than 50% complete	**R –** Retirement	
TS – Construction complete, but not yet in commercial operation		
M – Generating unit put in deactivated shutdown status		
RA – Previously deactivated or retired generator planned for reactivation		
OP – In commercial operation		
D – Generating unit capability decreased (rerated or relicensed)		
A – Generating unit capability increased (rerated or relicensed)		
FC – Existing generator planned for conversion to another fuel or energy source		
RP – Proposed for repowering or life extension		
CO – Change of ownership (including change of shares of jointly-owned units)		
OT – Other		

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
JOINTLY-OWNED MERCHANT GENERATOR UNITS
IN FLORIDA
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(11)	(12)	(13)
		GROSS CAPABILITY		NET CAPABILITY		COMMERCIAL		OWNERSHIP CODE					
FACILITY NAME	UNIT NO.	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	IN-SERVICE MO.	/ YEAR	PRIMARY OPERATING ENTITY NAME	% OWNER-SHIP	ENTITY 2 NAME	% OWNER-SHIP	ENTITY 3 NAME	% OWNER-SHIP
Orlando CoGen Limited, L.P.	1	125.2	135.0	125.0	135.0	9	1993	Northern Star Generating Svcs.	50	Atlantic Power	50		
Stanton Clean Energy Center	A	654.6	689.1	640.8	675.3	10	2003	Stanton Clean Energy, LLC	65	Orlando Utilities Commission	28	Florida Municipal Power Agency	7

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 3.01

EXISTING MERCHANT GENERATION FACILITIES IN FLORIDA

AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7) (8)	(9)	(10)		(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK						
						COMMERCIAL						FIRM		UNCOMMITTED				
	UNIT	LOCATION	UNIT	FUEL TYPE		IN-SERVICE	RETIREMENT	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN		UNIT	CONTRACT
FACILITY NAME	NO.	(COUNTY)	TYPE	PRI	ALT	MO. / YEAR	MO. / YEAR	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	OWNERSHIP	STATUS	STATUS
SANTA ROSA ENERGY CENTER, LLC (SREC)																		
SANTA ROSA ENERGY CENTER	CT01	SANTA ROSA	CT	NG		6 / 2003	--- / -----	165	178	161	173	143	158	18	15	MER	OP	NC
SANTA ROSA ENERGY CENTER	ST01	SANTA ROSA	CA	WH		6 / 2003	--- / -----	75	75	75	75	75	75	0	0	MER	OP	NC
NORTHERN STAR GENERATING SERVICES (NSG)																		
Vandolah Power Company LLC	1	Hardee	GT	NG	DFO	6 / 2002	6 / 2042	169	179	167	177	167	177	0	0	MER	OP	C
Vandolah Power Company LLC	2	Hardee	GT	NG	DFO	6 / 2002	6 / 2042	169	179	167	177	167	177	0	0	MER	OP	C
Vandolah Power Company LLC	3	Hardee	GT	NG	DFO	6 / 2002	6 / 2042	169	179	167	177	167	177	0	0	MER	OP	C
Vandolah Power Company LLC	4	Hardee	GT	NG	DFO	6 / 2002	6 / 2042	169	179	167	177	167	177	0	0	MER	OP	C
Orange Cogeneration Limited Partnership	1	Polk	CA	WH	NA	6 / 1995	6 / 2035	23	23	22	22	19	19	0	0	MER	OP	C
Orange Cogeneration Limited Partnership	2	Polk	CT	NG	NA	6 / 1995	6 / 2035	42	42	40	41	39	39	0	0	MER	OP	C
Orange Cogeneration Limited Partnership	3	Polk	CT	NG	NA	6 / 1995	6 / 2035	42	42	40	41	39	39	0	0	MER	OP	C
NEXTERA ENERGY RESOURCES (NEER)																		
OLEANDER POWER PROJECT	1	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	156.5	168.0	155.5	167.0	0.0	0.0	155.5	167.0	MER	OP	NC
OLEANDER POWER PROJECT	2	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	157.1	168.6	156.1	167.6	156.1	167.6	0.0	0.0	MER	OP	C
OLEANDER POWER PROJECT	3	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	157.7	169.2	156.7	168.2	156.7	168.2	0.0	0.0	MER	OP	C
OLEANDER POWER PROJECT	4	BREVARD	GT	NG	DFO	6 / 2005	--- / -----	157.2	168.6	156.2	167.6	156.2	167.6	0.0	0.0	MER	OP	C
OLEANDER POWER PROJECT	5	BREVARD	GT	NG	DFO	12 / 2007	--- / -----	160.4	173.2	159.4	172.2	159.4	172.2	0.0	0.0	MER	OP	C
STANTON ENERGY CENTER	A	ORANGE	CT	NG	DFO	10 / 2003	--- / -----	425.5	447.9	416.5	438.9	416.5	438.9	0.0	0.0	MER	OP	C
Origis Energy																		
FL Solar 7, LLC (Rice Creek)	N/A	PUTNAM	PV	SUN	N/A	12 / 2024	--- / -----	78.8	78.8	75	75	75	75	N/A	N/A	Origis Energy	OP	NC
								TOTALS:		**2,281**	**2,416**	**2,103**	**2,228**	**174**	**182**			

(1) This is the generator nameplate rating.
(2) This is a jointly owned unit. Only the amount owned by NEER is shown.

2025

LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
FRCC Form 3.01

PLANNED AND PROSPECTIVE CHANGES TO MERCHANT GENERATION FACILITIES IN FLORIDA
AS OF DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK						
					FUEL TYPE		EFFECTIVE CHANGE DATE					FIRM		UNCOMMITTED				
UTIL	FACILITY NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	PRI	ALT	MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	OWNERSHIP	UNIT STATUS	CONTRACT STATUS

NO ACTIVITY REPORTED

2025

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC Form 3.01

PLANNED AND PROSPECTIVE CHANGES TO MERCHANT GENERATION FACILITIES

IN FLORIDA

AS OF DECEMBER 31, 2024

ORDERED BY IN-SERVICE DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
								GROSS CAPABILITY		NET CAPABILITY		POTENTIAL EXPORT TO GRID AT TIME OF PEAK						
					FUEL TYPE		EFFECTIVE					FIRM		UNCOMMITTED				
UTIL	FACILITY NAME	UNIT NO.	LOCATION	UNIT TYPE	PRI	ALT	CHANGE DATE MO. / YEAR	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	SUM (MW)	WIN (MW)	OWNERSHIP	UNIT STATUS	CONTRACT STATUS
	2025 - 2034																	
	NO ACTIVITY REPORTED																	
	2024 - 2033 TOTALS:							**0.0**	**0.0**	**0.0**	**0.0**							

2025

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF MERCHANT FIRM CAPACITY AND ENERGY CONTRACTS

AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)
PURCHASING ENTITY	**SELLING ENTITY**	**CONTRACT TERM**		**NET CAPABILITY**		**DESCRIPTION**
		FROM (MM/DD/YY)	**TO (MM/DD/YY)**	**SUMMER (MW)**	**WINTER (MW)**	
SEC	OLEANDER POWER PROJECT LP	1/1/2010	12/31/2027	156	168	Oleander Unit 2 Capacity and Energy. Fuel is purchased by PPA off takers
SEC	OLEANDER POWER PROJECT LP	1/1/2010	12/31/2027	157	168	Oleander Unit 3 Capacity and Energy. Fuel is purchased by PPA off takers
DEF	VANDOLAH POWER CO.	6/1/2012	5/31/2027	667	708	Contract does not call for Vandolah to provide a specific MW output, but instead calls for the performance of an annual capacity test to determine the MW output for that year. Data provided is based on the contract results for June 2024 (Summer) and December 2024 (Winter).
DEF	ORGANGE COGEN	11/19/1991	12/31/2025	104	104	Firm capacity and energy.
FMPA	OLEANDER POWER PROJECT LP	12/16/2007	12/15/2027	159	172	Oleander Unit 5 Capacity and Energy. Fuel is purchased by PPA off takers
OUC	Stanton Clean Energy, LLC	10/1/2003	12/31/2031	333	351	NEER Ownership contracted to OUC (Stanton A) for Capacity and Energy. Fuel is purchased by PPA off takers
Georgia Power Company	Santa Rosa	5/1/2024	12/31/2028	218	233	Power Purchase Agreement between Georgia Power Company and Santa Rosa Energy Center, LLC.

2025
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF MERCHANT GENERATING FACILITIES
IN THE FRCC REGION
AS OF JANUARY 1, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	SUMMER				WINTER		
YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED (MW)	NET CAPABILITY (MW)	YEAR	FIRM NET TO GRID (MW)	UNCOMMITTED (MW)	NET CAPABILITY (MW)
2025	1,794	174	1,968	2025/26	1,800.0	286.0	2,086.0
2026	1,690	278	1,968	2026/27	1,800.0	286.0	2,086.0
2027	1,023	945	1,968	2027/28	584.0	1,502.0	2,086.0
2028	551	1,417	1,968	2028/29	351.0	1,735.0	2,086.0
2029	333	1,635	1,968	2029/30	351.0	1,735.0	2,086.0
2030	333	1,635	1,968	2030/31	351.0	1,735.0	2,086.0
2031	333	1,635	1,968	2031/32	0.0	2,086.0	2,086.0
2032	0	1,968	1,968	2032/33	0.0	2,086.0	2,086.0
2033	0	1,968	1,968	2033/34	0.0	2,086.0	2,086.0
2034	0	1,968	1,968	2034/35	0.0	2,086.0	2,086.0

NOTES: Only columns (4) and (8) are cumulative on a seasonal basis.

Columns (2), (3), (6), and (7) represent the seasonal capabilities available as they have been modified by contract terms.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 14

2025 LTRA

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026

Table of Contents

Preface 3
About This Assessment 4
Reading This Report 5
Executive Summary 6
Capacity and Energy Risk Assessment 6
Trends and Reliability Implications 9
Recommendations 10
Capacity and Energy Risk Assessment 12
Assessment Approach 12
Risk Categories 12
Resource and Demand Projections 23
Reducing Resource Capacity and Energy Risk 24
Demand Trends and Implications 25
Demand and Energy Projections 25
Reliability Implications 29
Resource Mix Changes 30
Planned On-Peak Capacity Additions 31
Transmission Development and Interregional Transfer Capability 37
Transmission Projects 37
Interregional Transfer Capability Study (Canadian Analysis) 38
Regional Assessments Dashboards 41
MISO 42
MRO-Manitoba Hydro 49
MRO-SaskPower 54
MRO-SPP 59
NPCC-Maritimes 63
NPCC-New England 68
NPCC-New York 74
NPCC-Ontario 80
NPCC-Québec 86
PJM 90
SERC-Central 95
SERC-East 102
SERC-Florida Peninsula 112
SERC-Southeast 120
Texas RE-ERCOT 128
WECC-Alberta 134
WECC-Basin 138
WECC-British Columbia 143
WECC-California 147
WECC-Mexico 151
WECC-Northwest 154
WECC-Rocky Mountain 159
WECC-Southwest 163
Demand Assumptions and Resource Categories 167
Methods and Assumptions 171
Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area 175
Recommendations and ERO Actions Summary 177

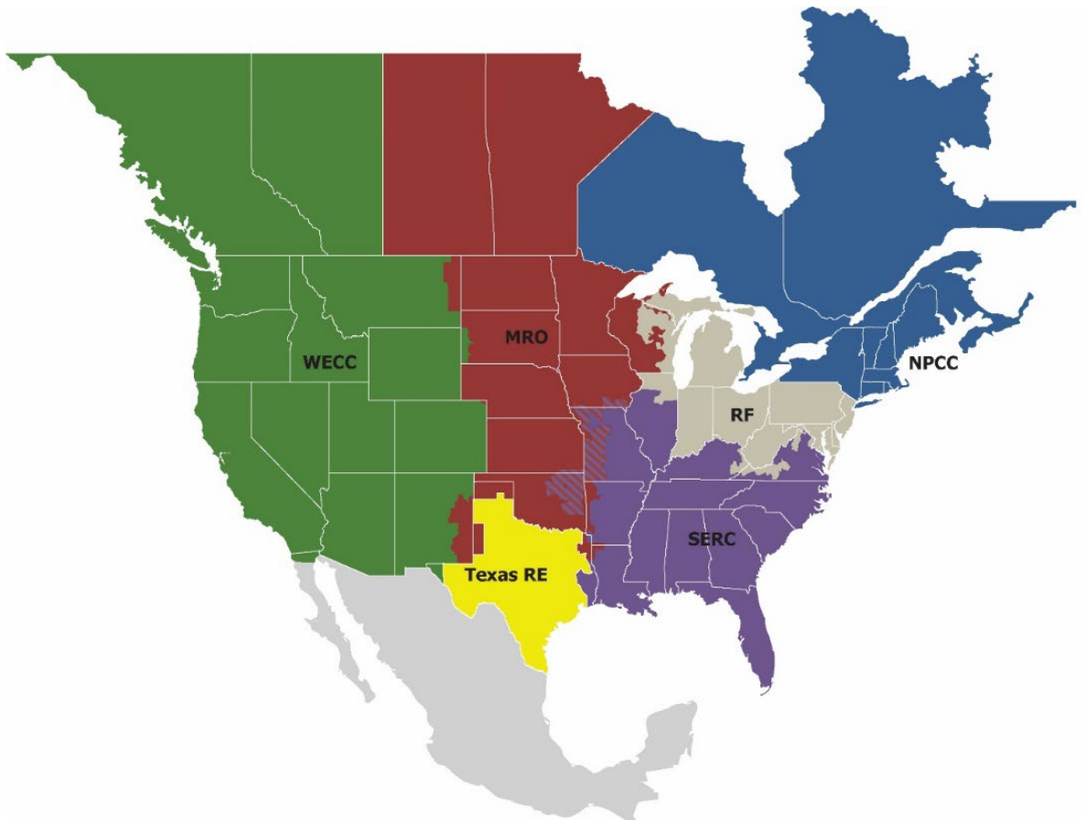
Preface

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 Procedure[1] and Title 18, § 39.11[2] 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.
- 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

[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 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.

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**.

[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**.

[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.

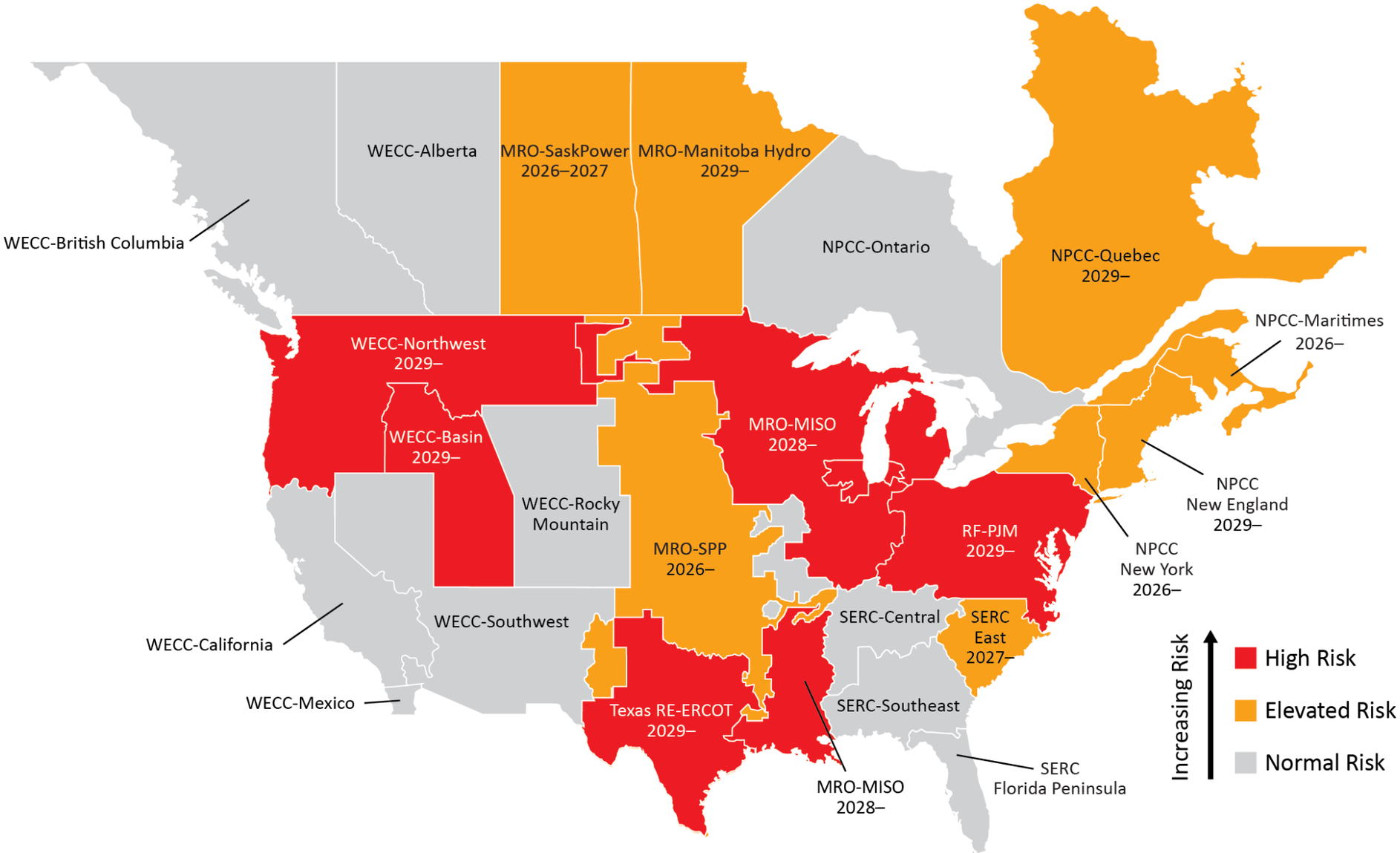


Figure 1: Risk Area Summary 2026–2030

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 *Expedited Resource Addition Study* (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 *Expedited Resource Adequacy Study* 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 Star Report*.
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 Plan[10] 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.

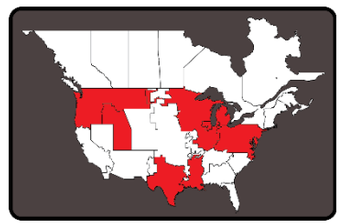
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

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.

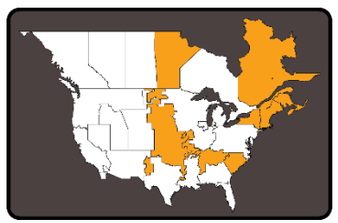
For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- 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*.

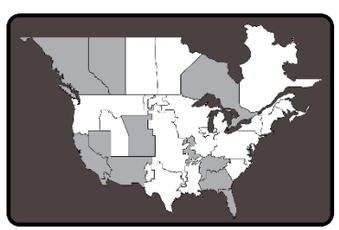
- Resource adequacy target(s) established by regulatory authority or system operator are not met.

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 extreme[14] 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]				
Summer-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026**	**2027**	**2028**	**2029**	**2030**	**2026**	**2027**	**2028**	**2029**	**2030**
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	**2027**	**2029**	**2027**	**2029**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
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.

Table 3: MISO Base-Case Summary of Results

	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.

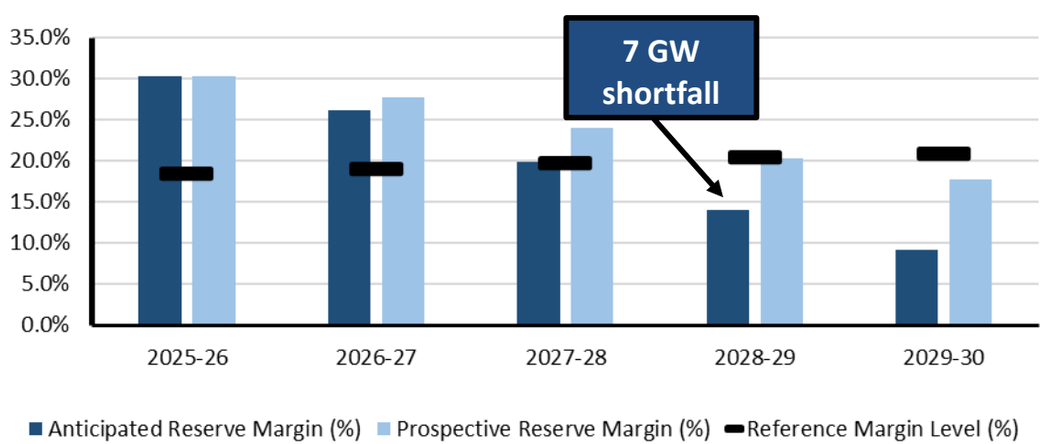
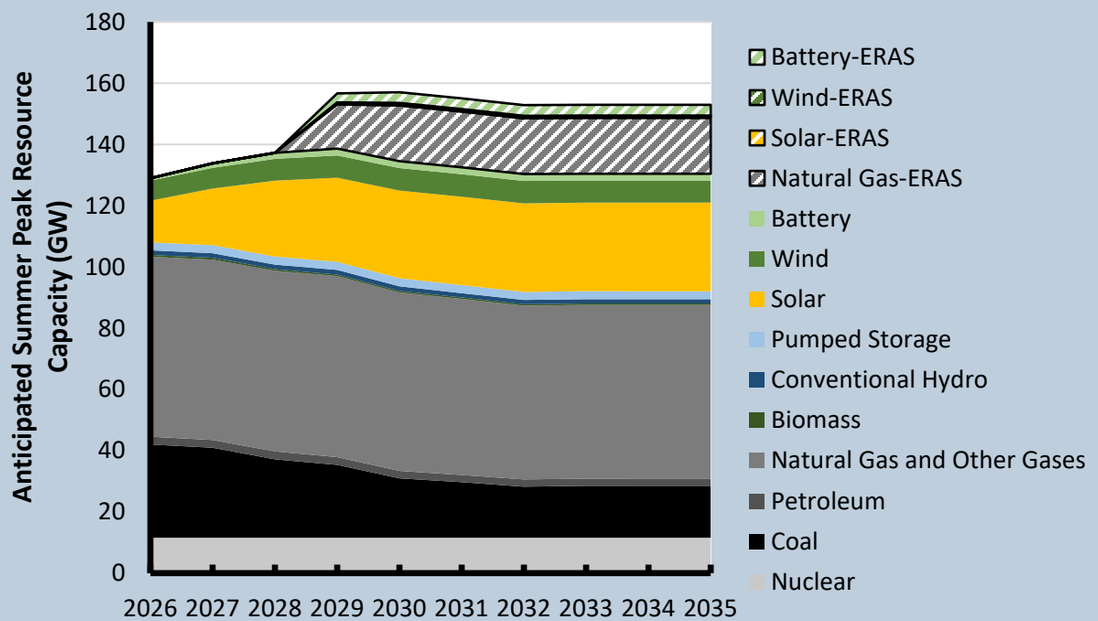


Figure 2: MISO Winter Planning Reserve Margins

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.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

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**).

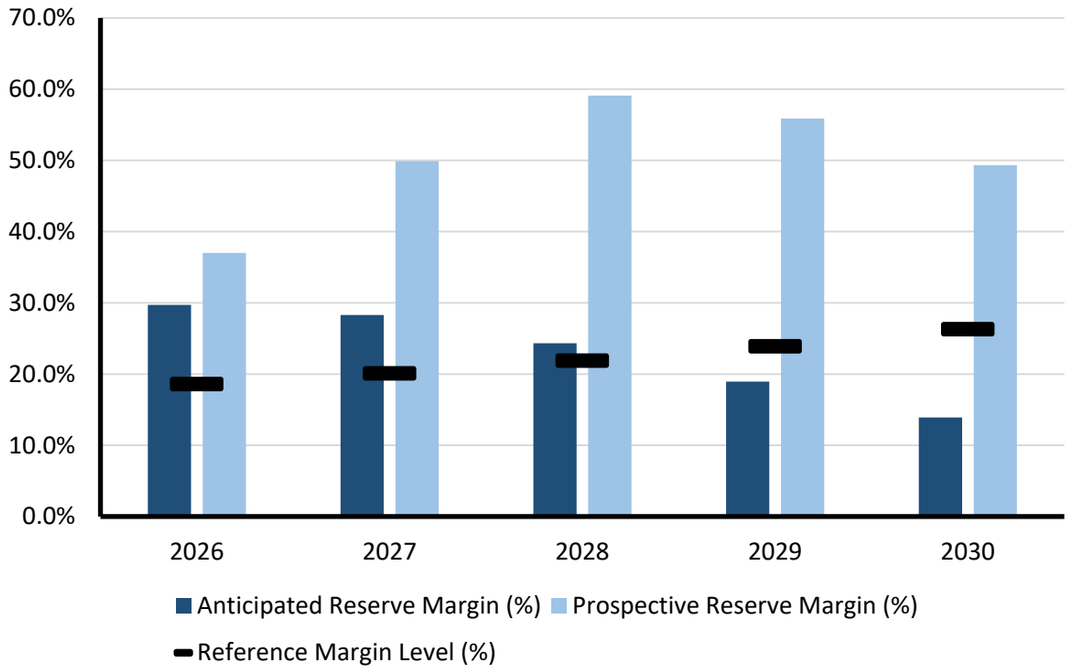


Figure 3: PJM Summer Planning Reserve Margins

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**).

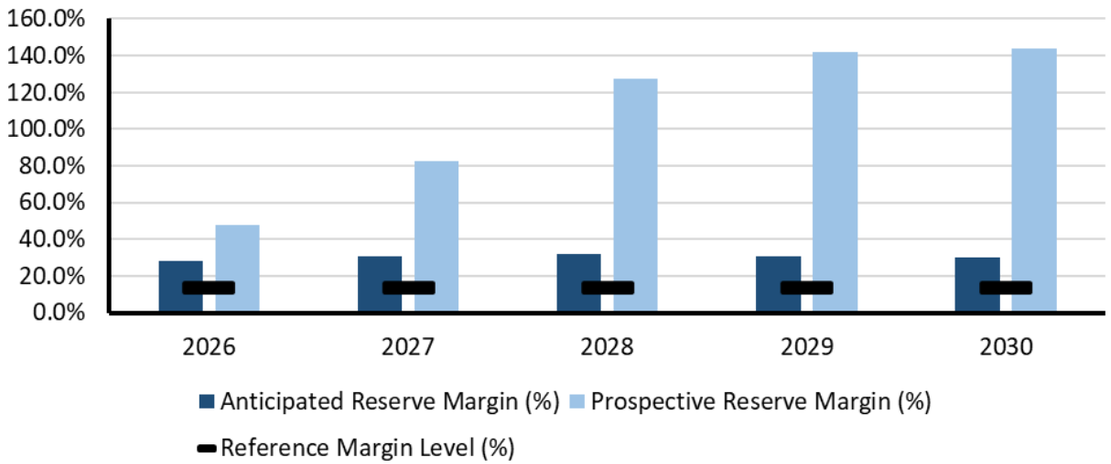


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

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 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

[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.

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.

Table 8: MRO-Manitoba ProbA Summary of Results			
	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)**.

Table 9: MRO-SaskPower Base-Case Summary of Results			
	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.

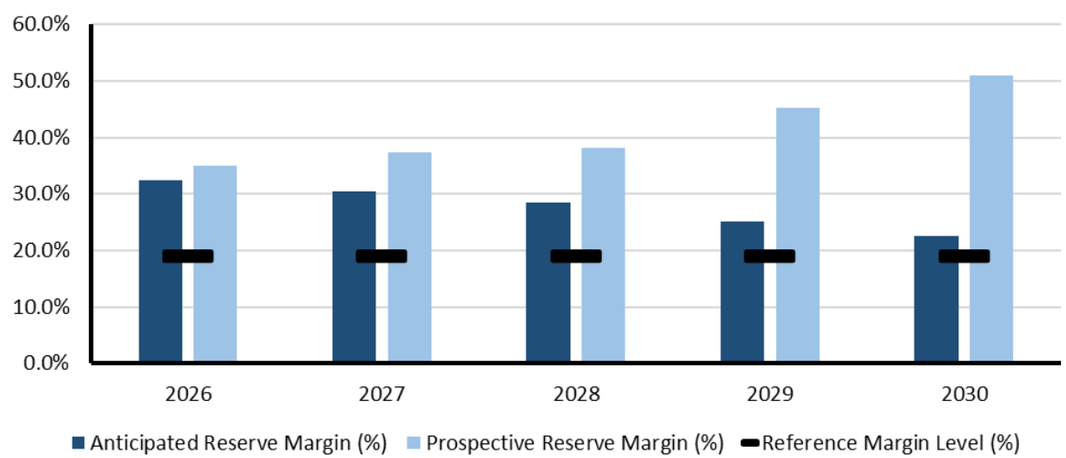


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

[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.

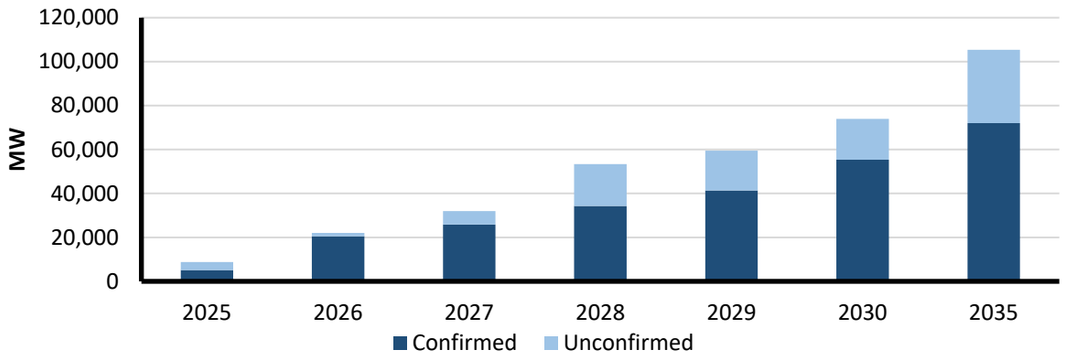


Figure 6: Projected Generation Retirement Capacity Through 2035

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.

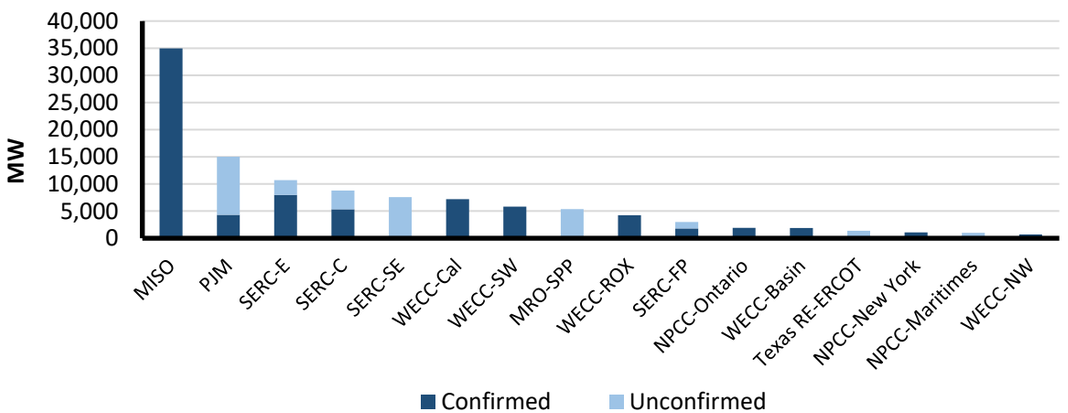


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

[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.

Table 15: Resource Adequacy Program Attributes

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.**

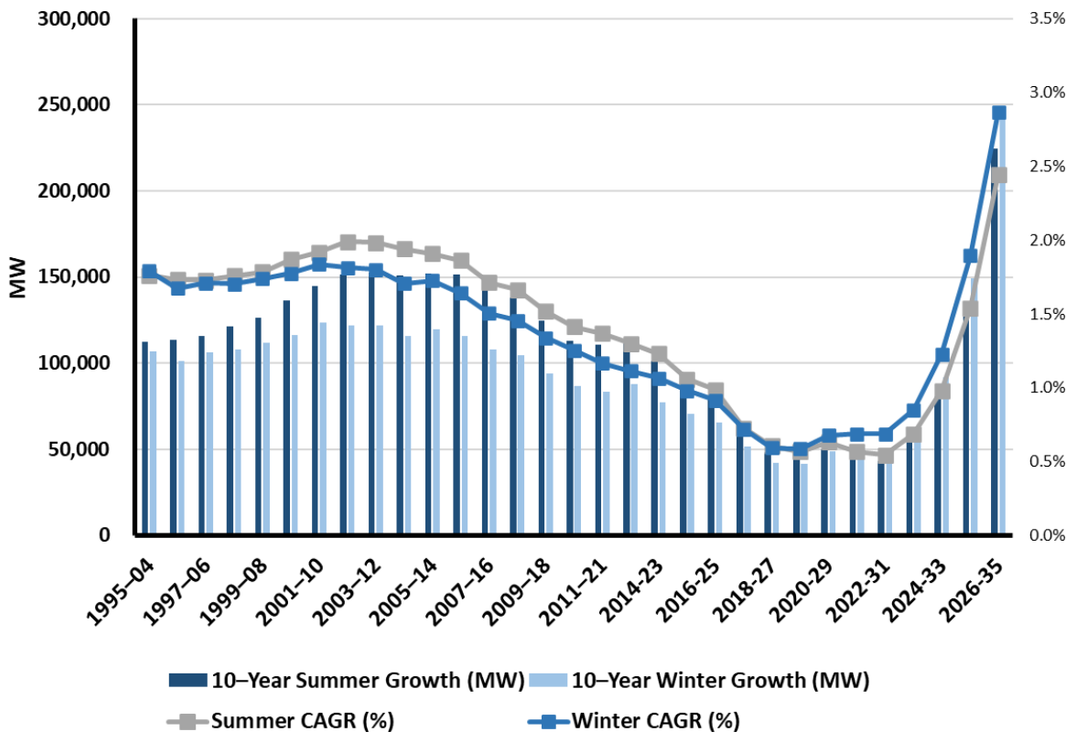


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

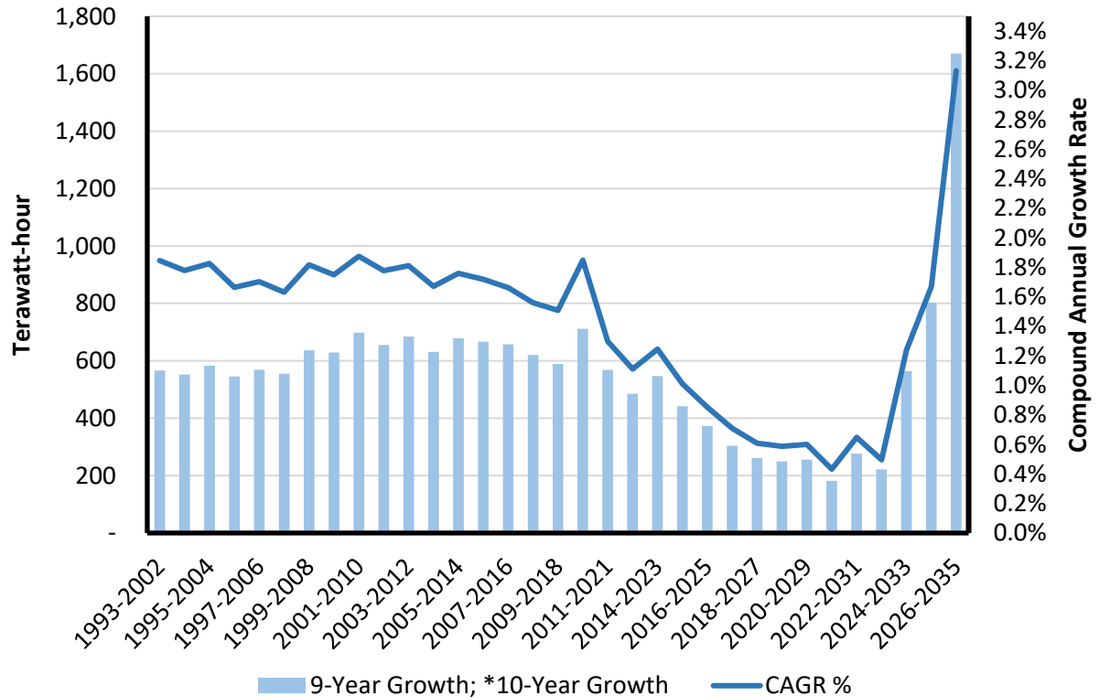


Figure 9: Net Energy for Load Growth and Rate Projections

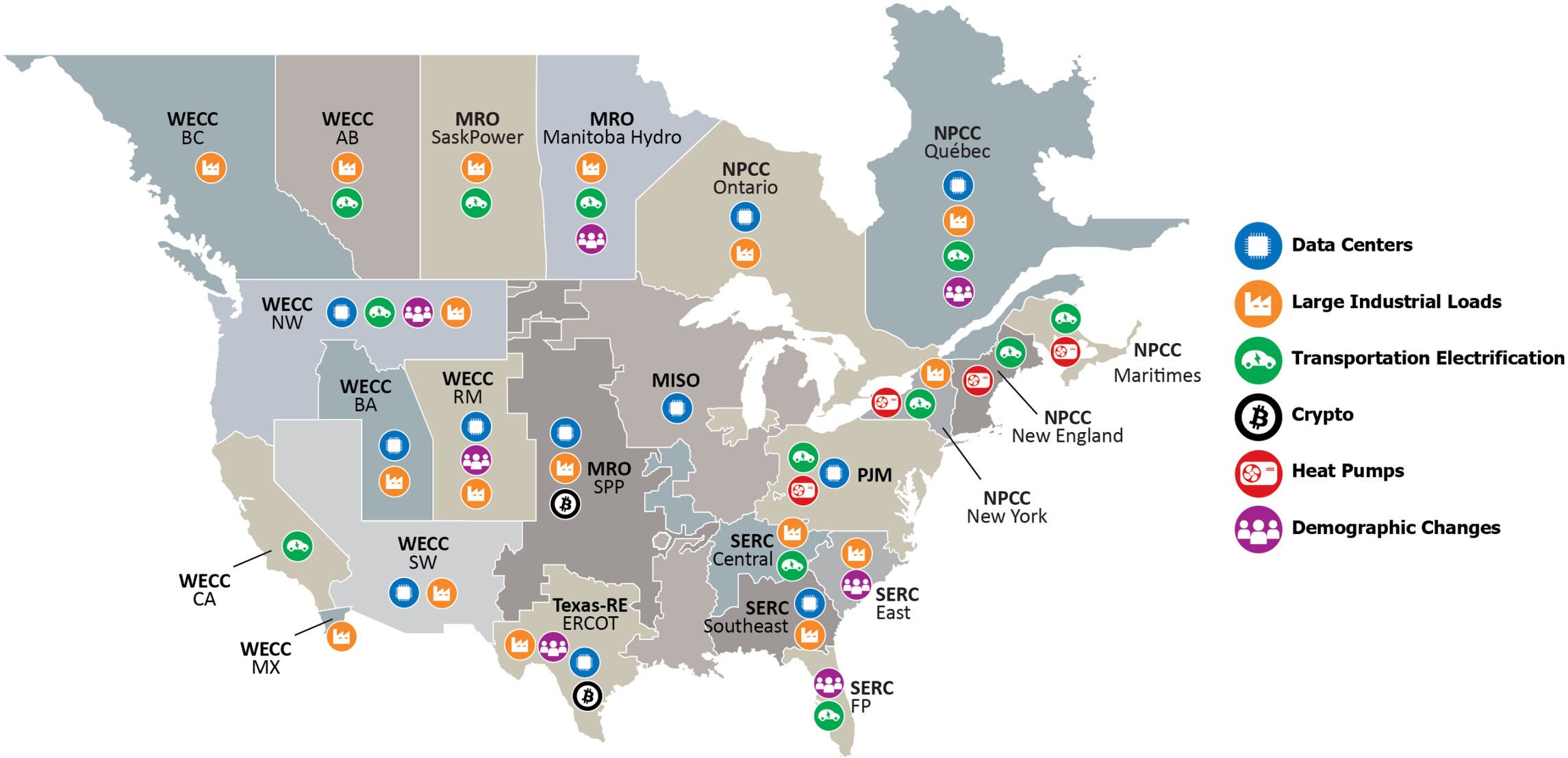


Figure 10: Primary Demand Drivers by Assessment Area

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.

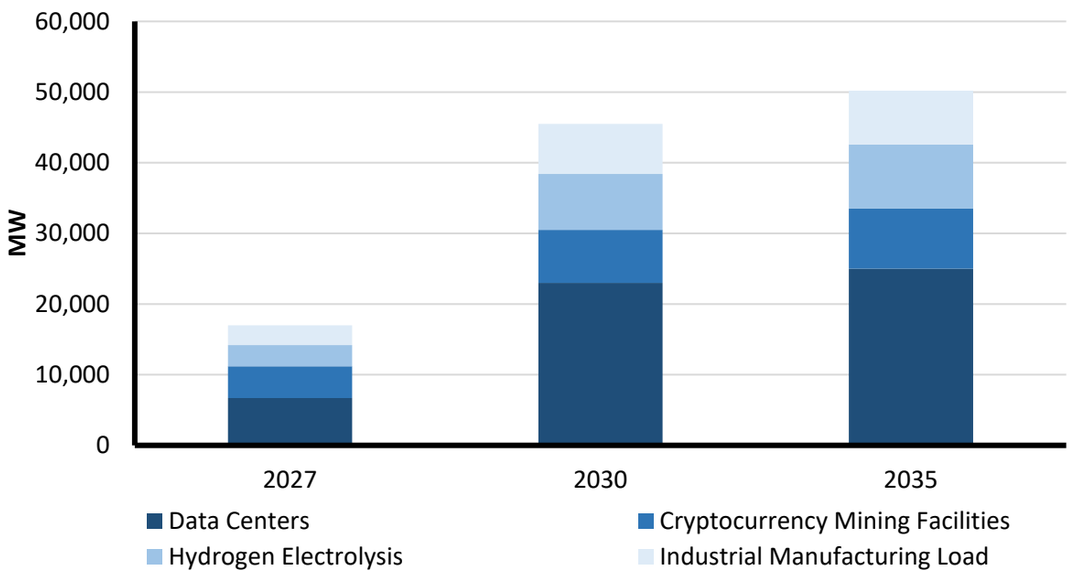


Figure 11: Large-Load Projection Breakdown in ERCOT

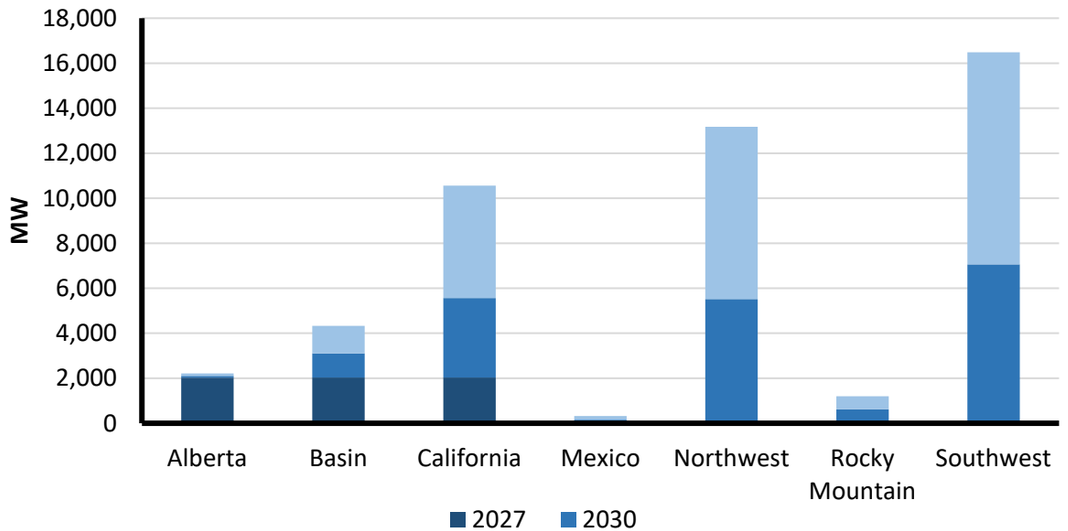


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

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 events[21] 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 assessments 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.

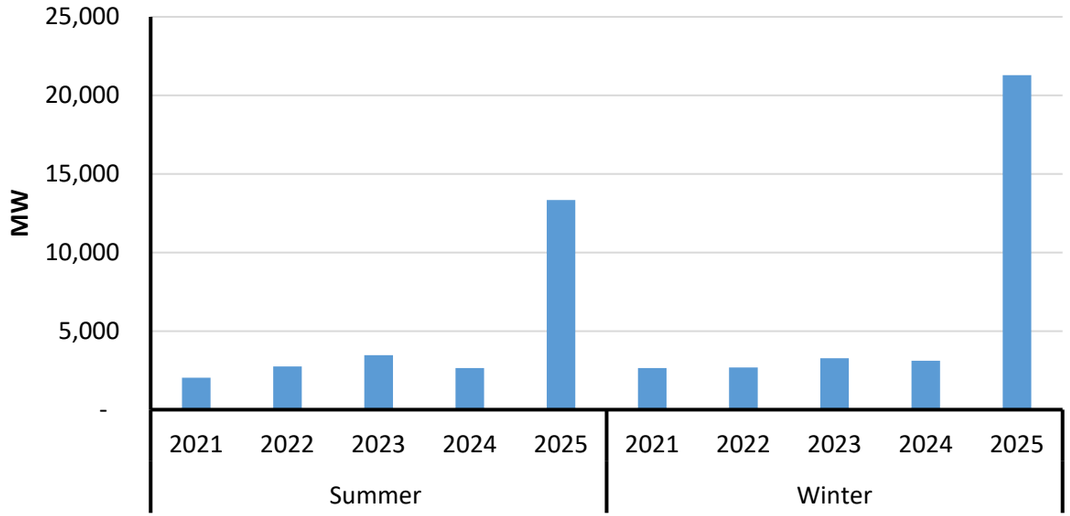


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

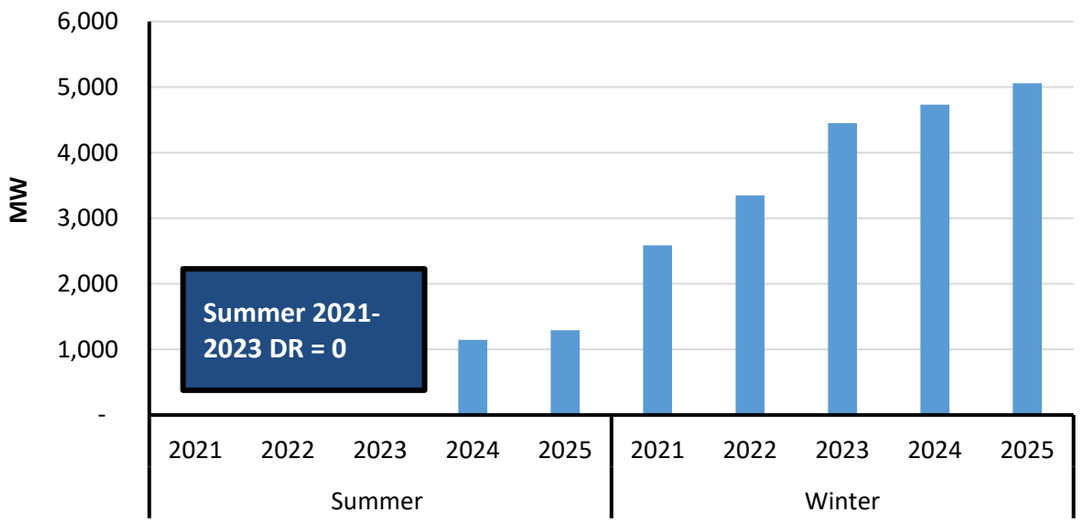


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

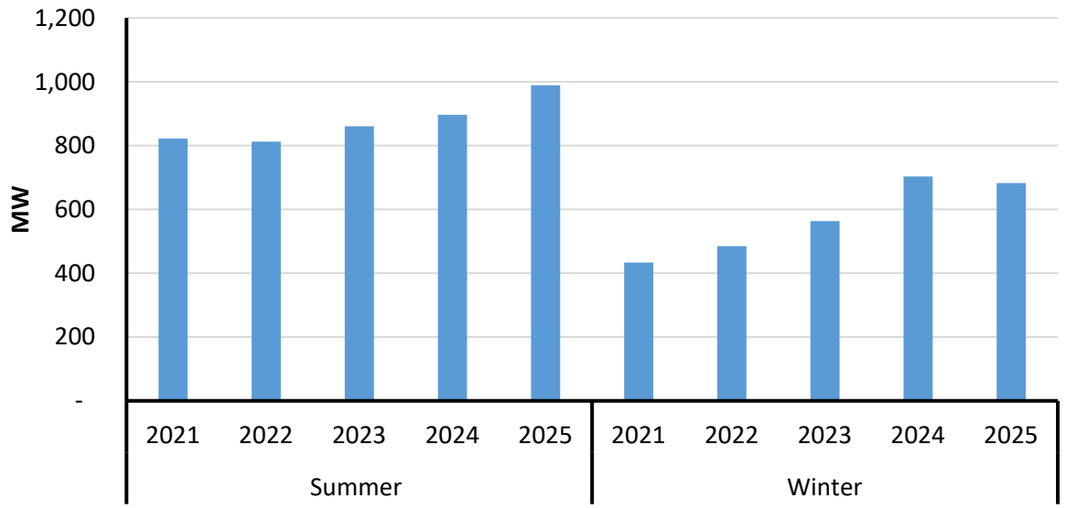


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

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).

Table 16: Existing BPS Resource On-Peak Capacity

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.

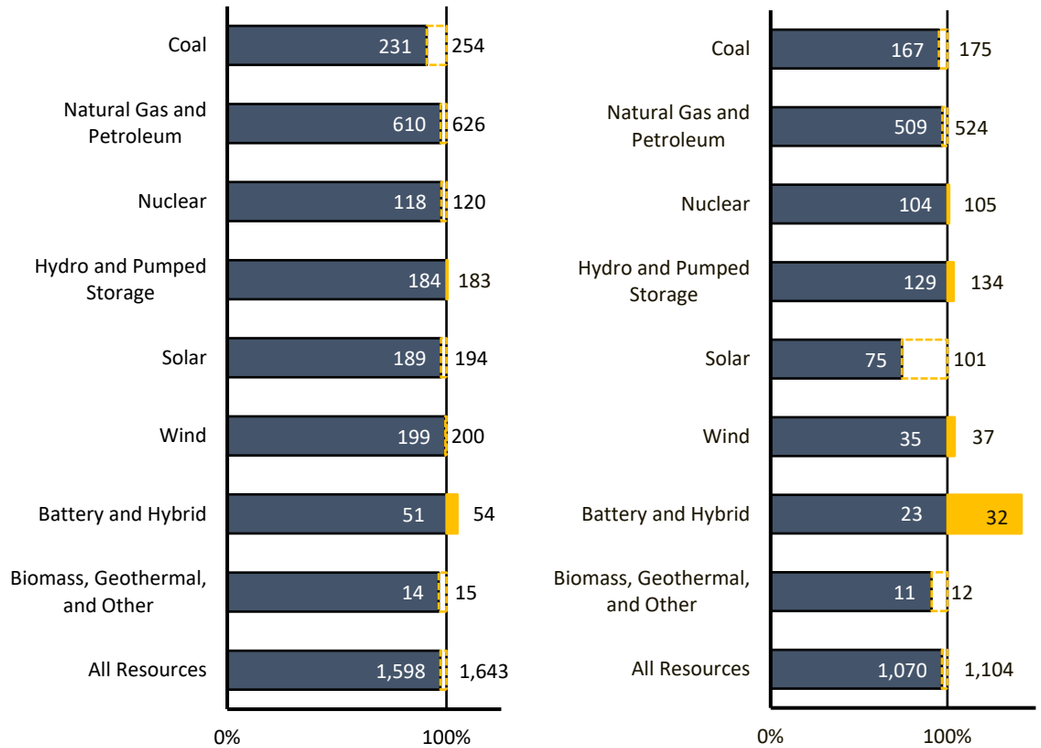


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections

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.

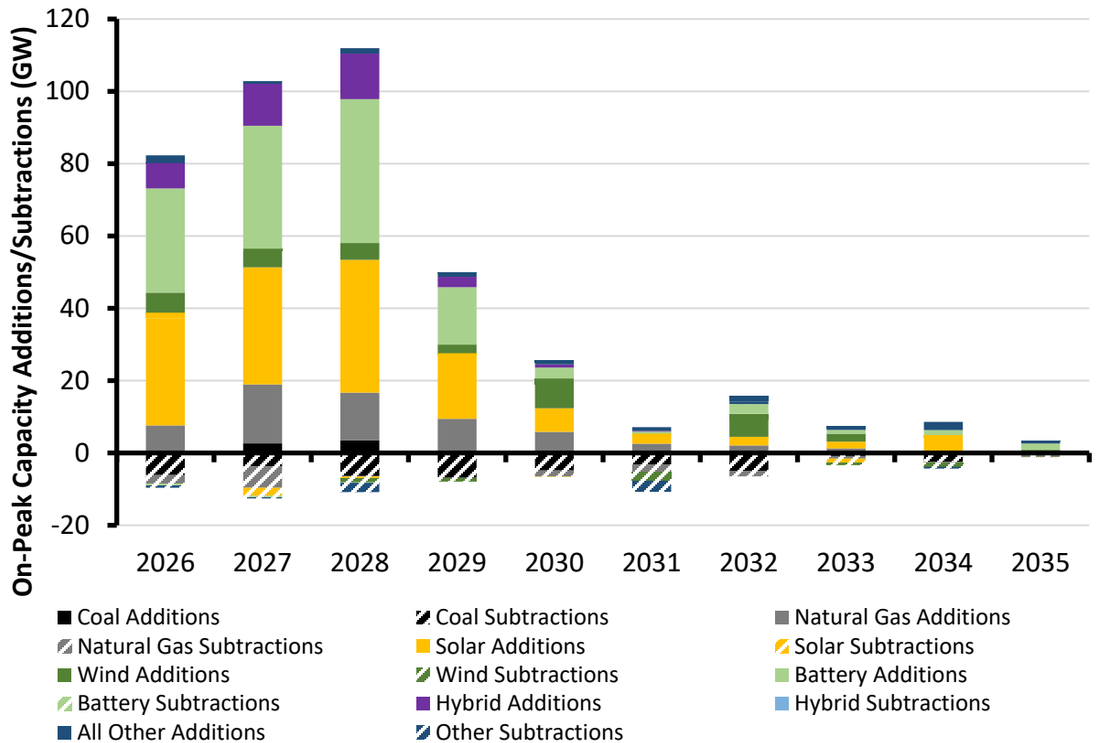


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

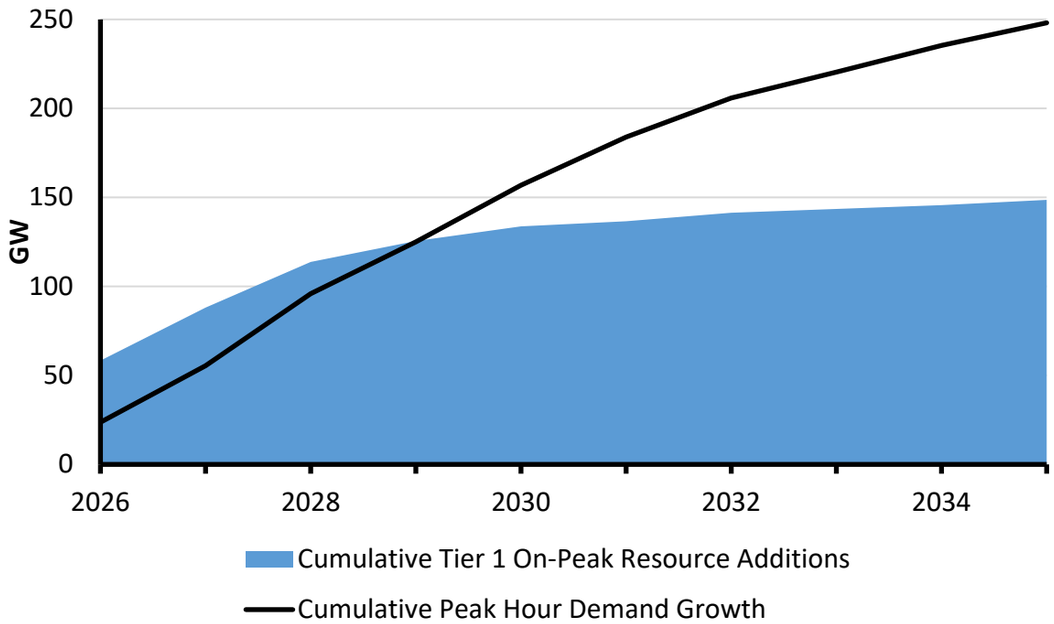


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

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.

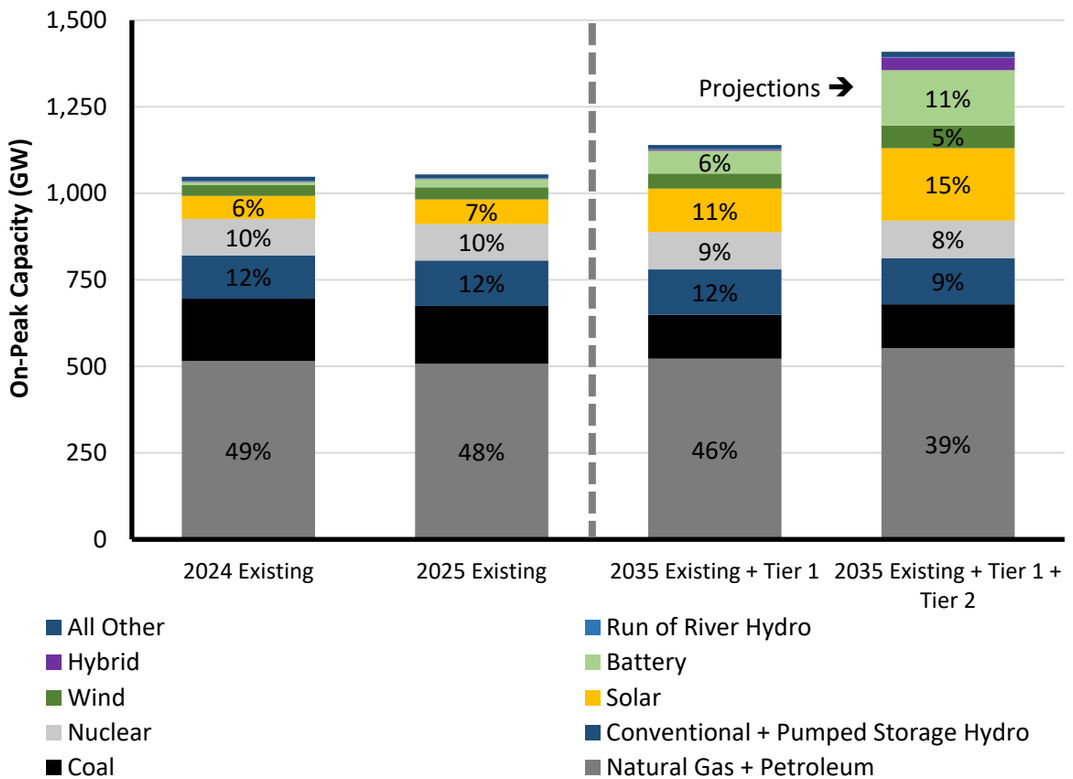


Figure 19: North America On-Peak Capacity Shares by Resource Type

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.

Table 17: Measures of Frequency Response

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 studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment

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.

[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 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.

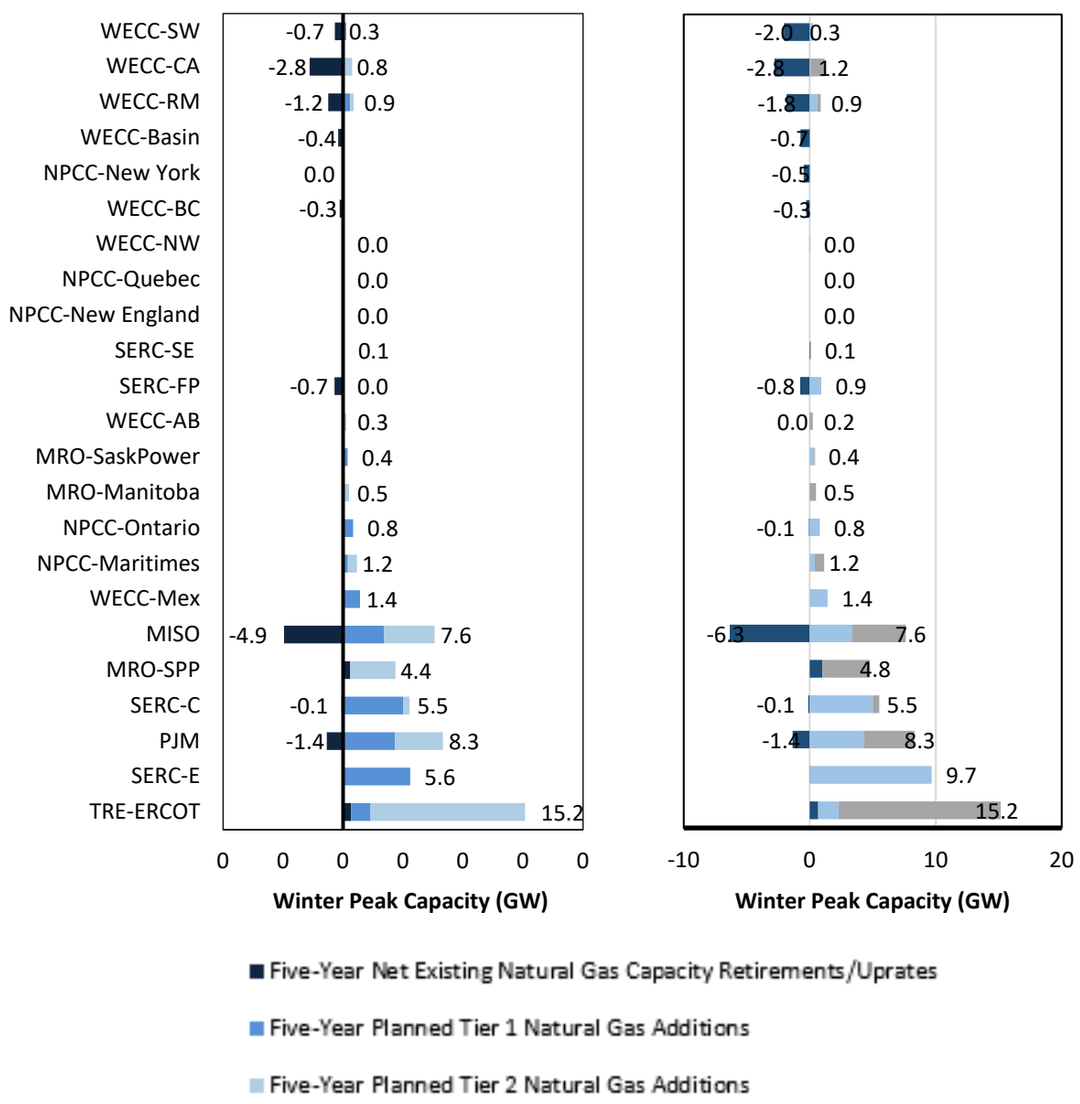


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

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.

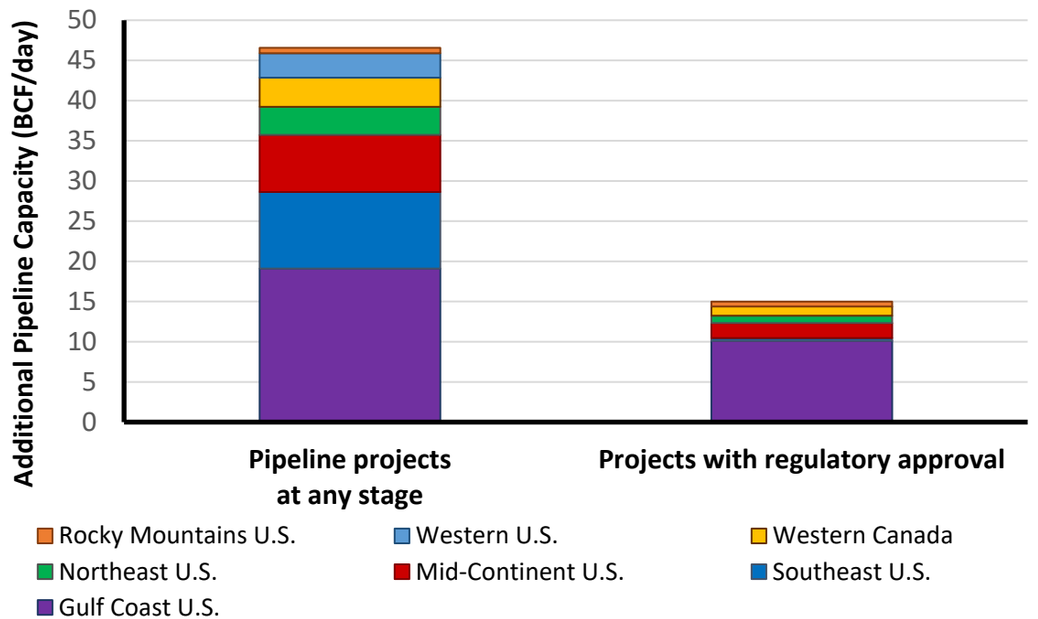


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

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.

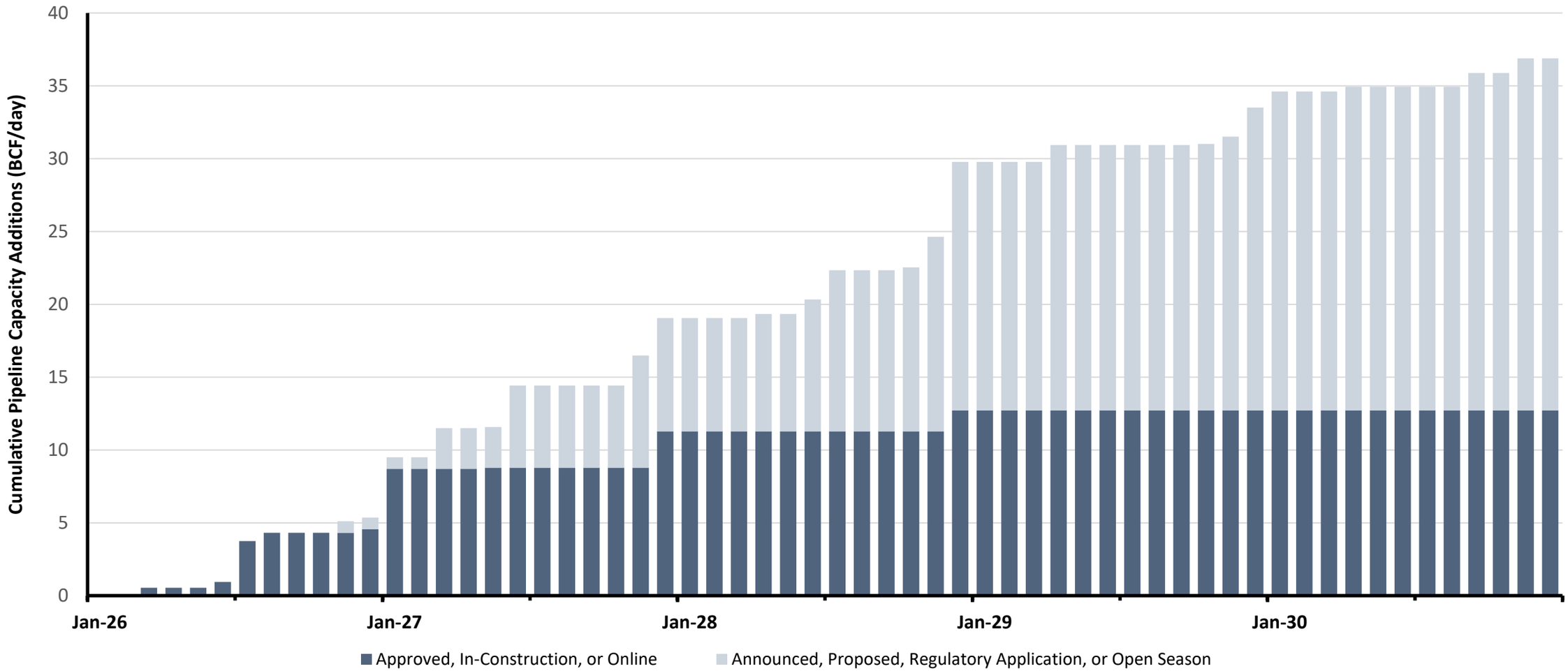


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

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.

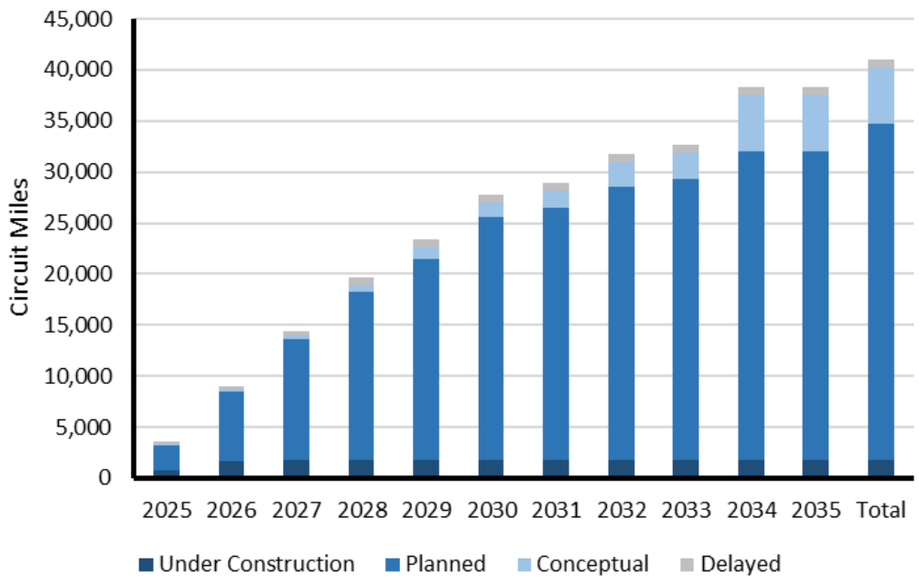


Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]

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 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.

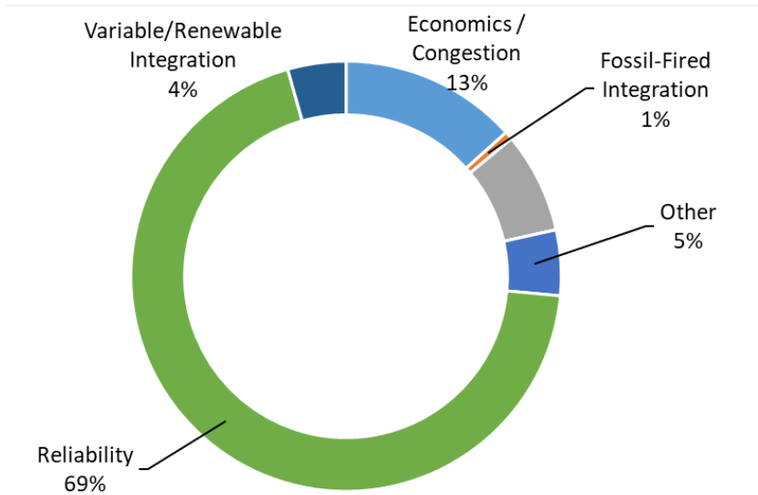


Figure 24: Future Transmission Circuit Miles by Primary Driver

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 Appalaches-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.

[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.

[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 capability[30] 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 TPR[33] but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

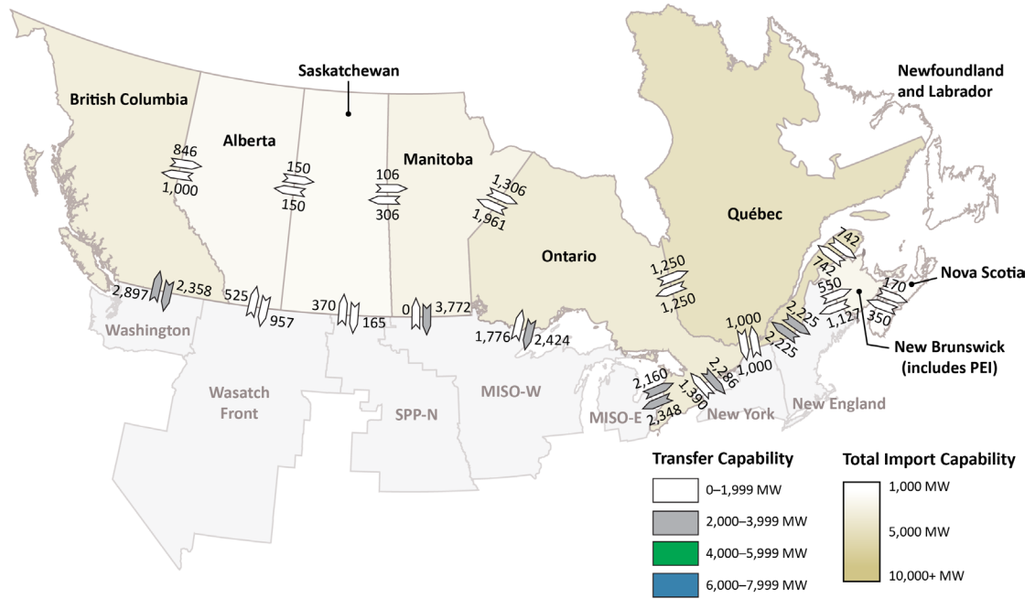


Figure 25: Transfer Capabilities (Summer)

[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 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.

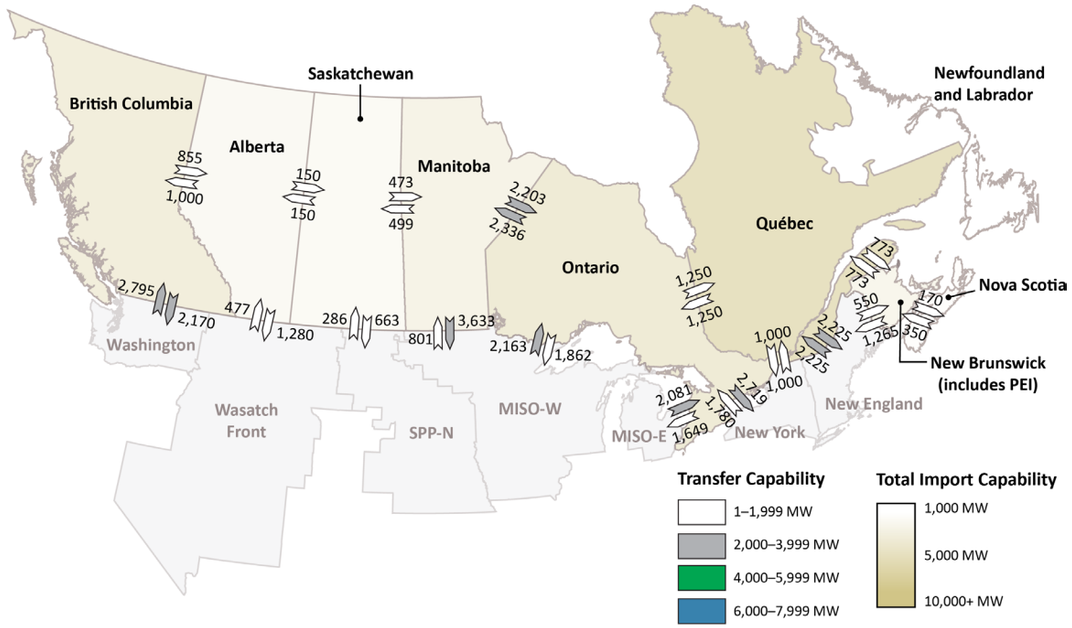


Figure 26: Transfer Capabilities (Winter)

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

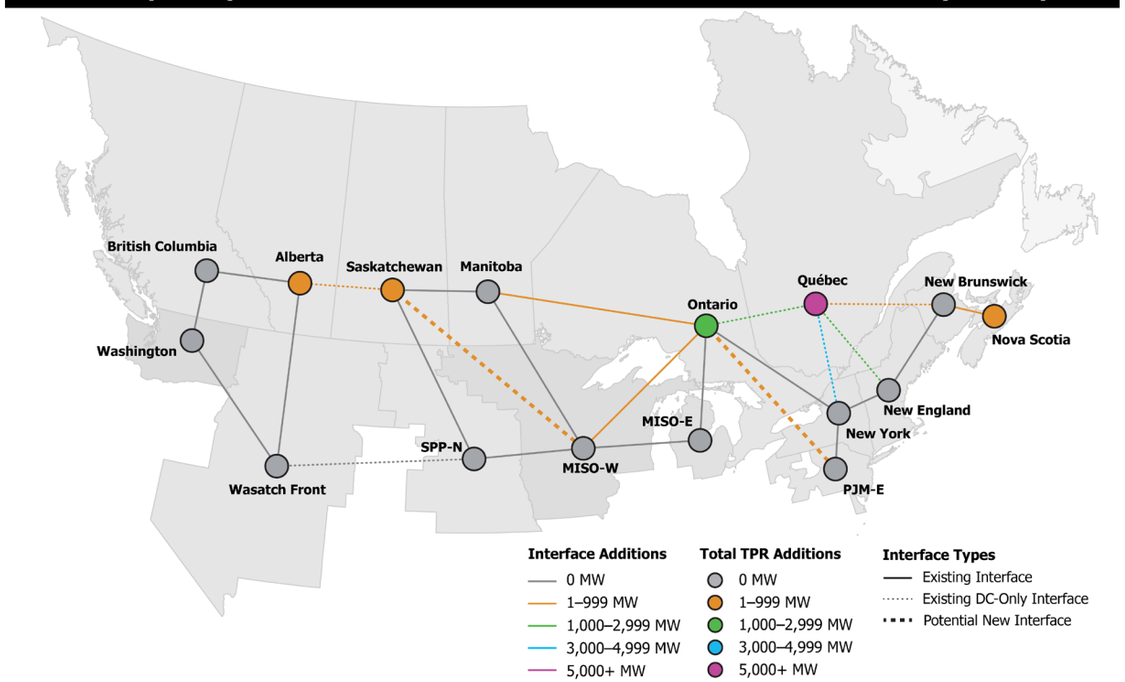
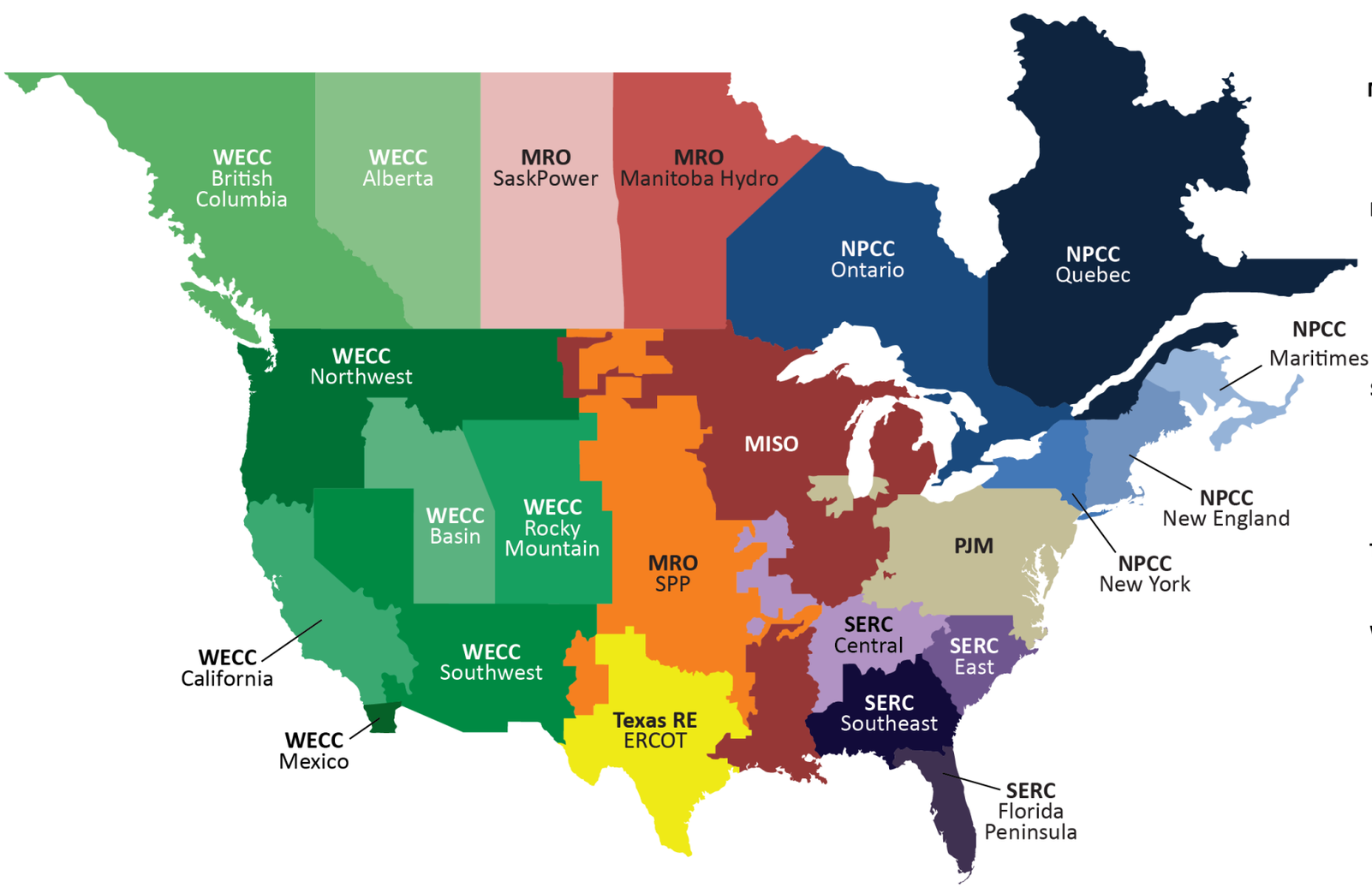


Figure 27: Transfer Capability Additions

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 *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP *(Southwest Power Pool)*

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Florida Peninsula
- SERC-Southeast

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

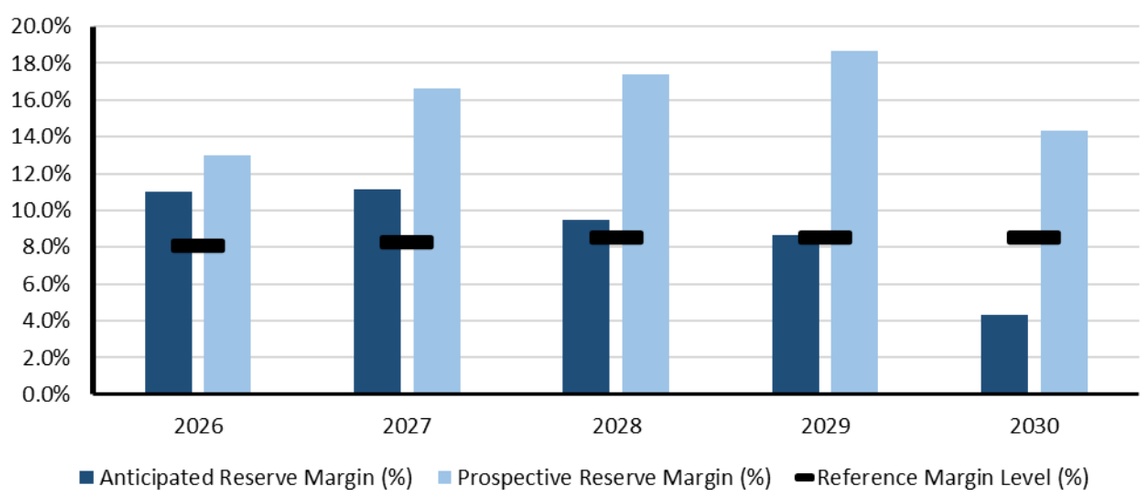
WECC – Western Electricity Coordinating Council
- WECC-Alberta
- WECC-Basin
- WECC-British Columbia
- WECC-California
- WECC-Mexico
- WECC-Northwest
- WECC-Rocky Mountain
- WECC-Southwest

MISO

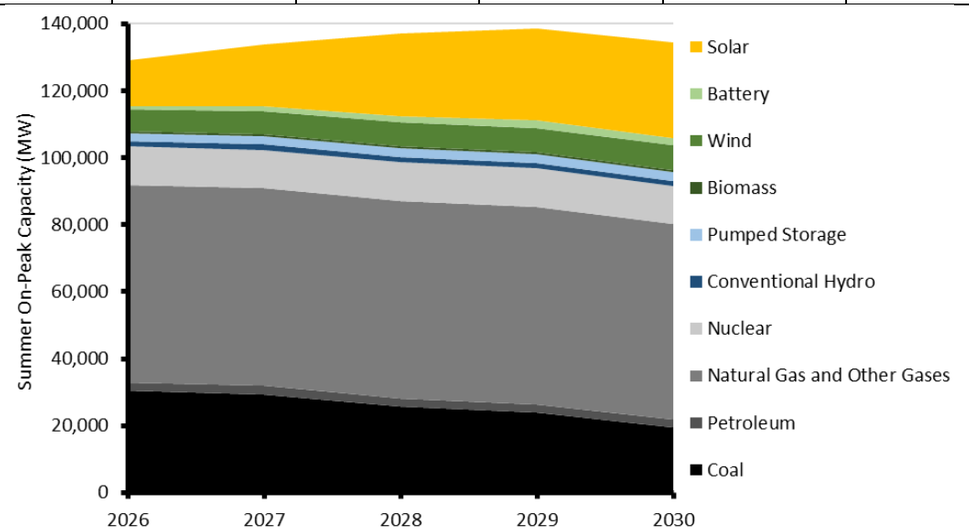
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery 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.

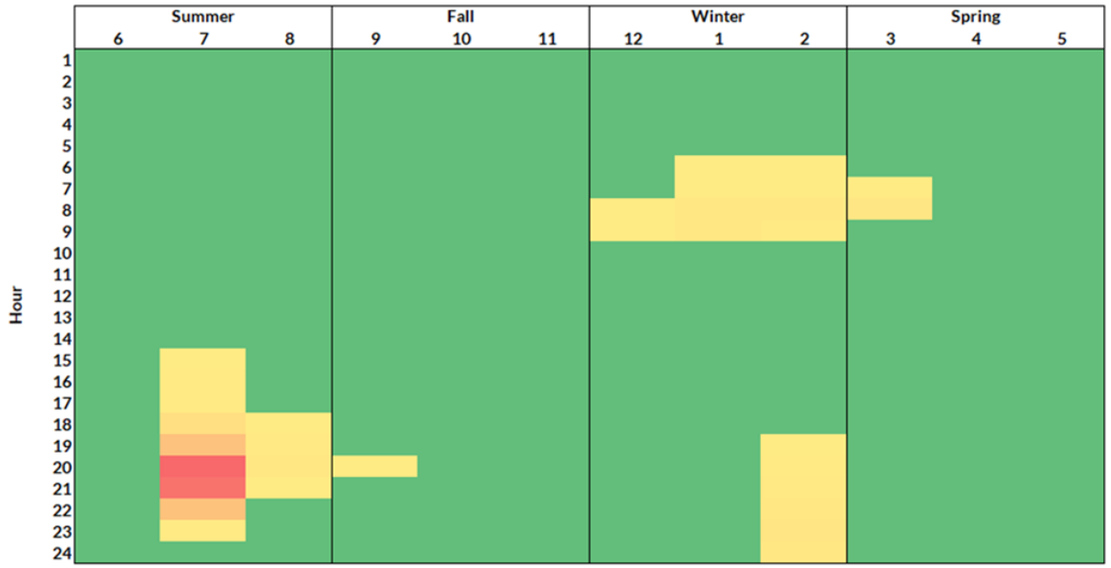
Base-Case Summary of Results

	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

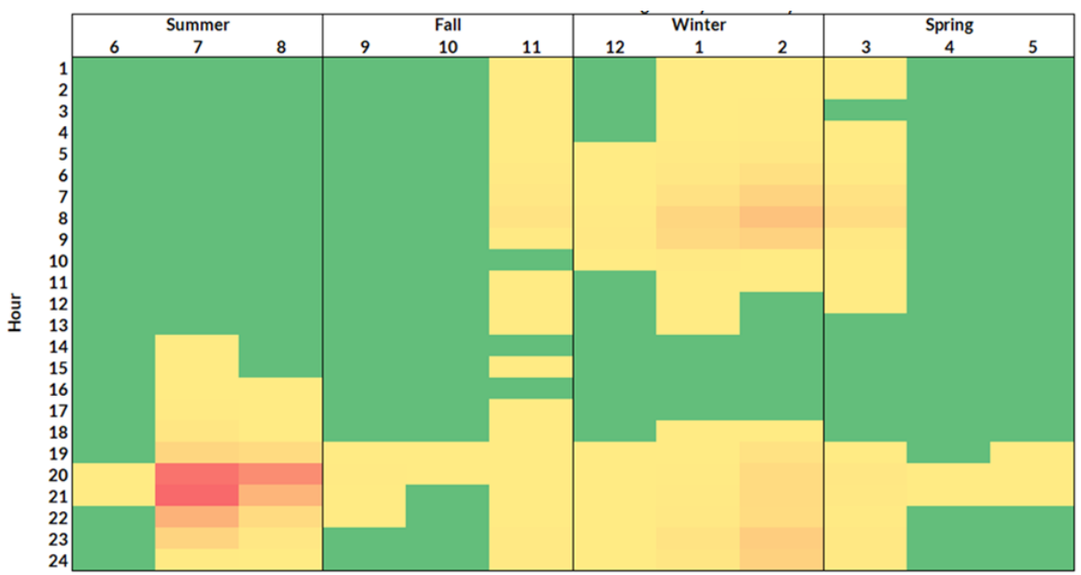
*Provides the 2024 ProbA Results for Comparison

**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.

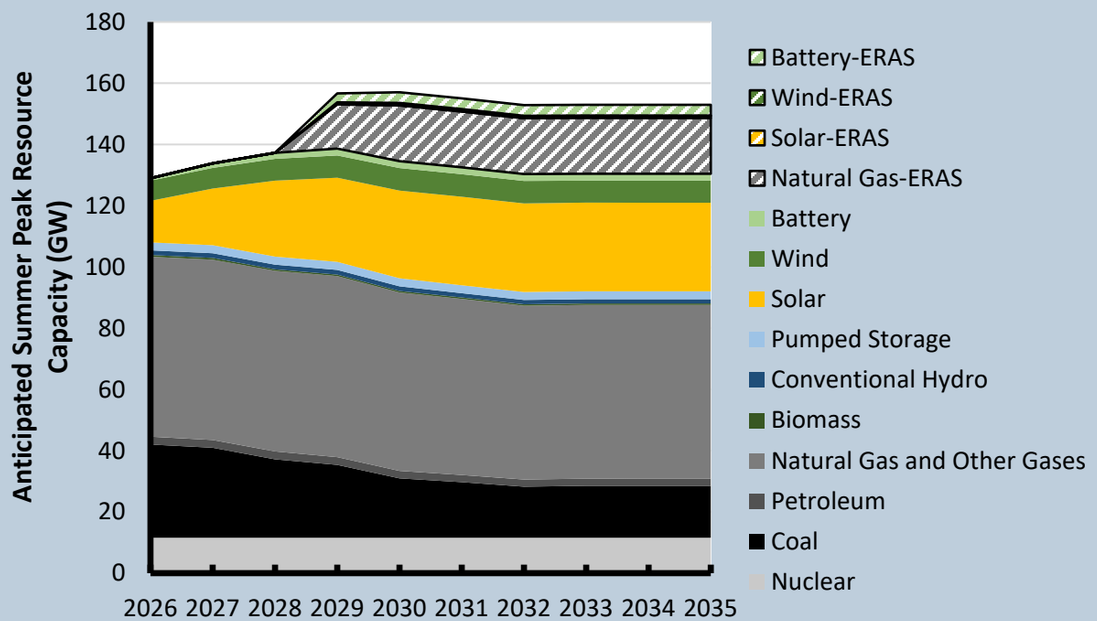
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited 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.

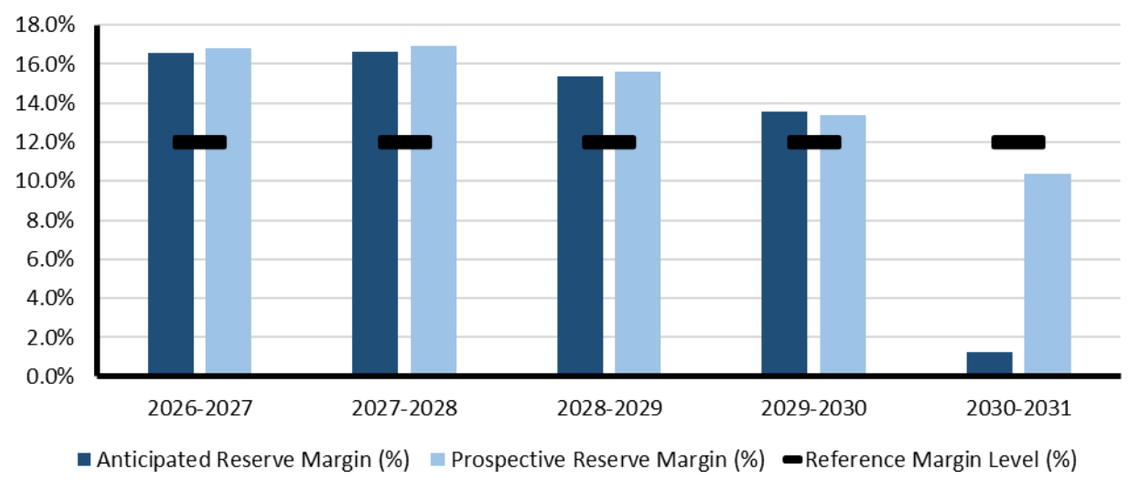
Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue 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

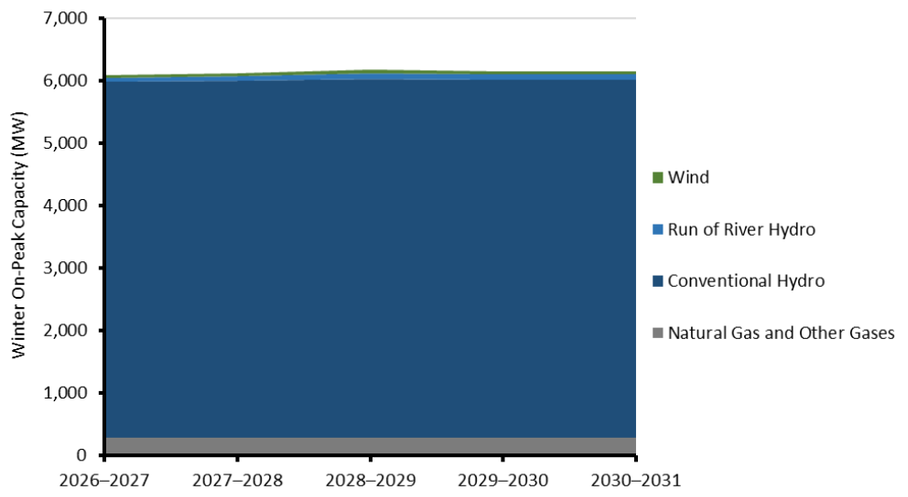
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in 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.

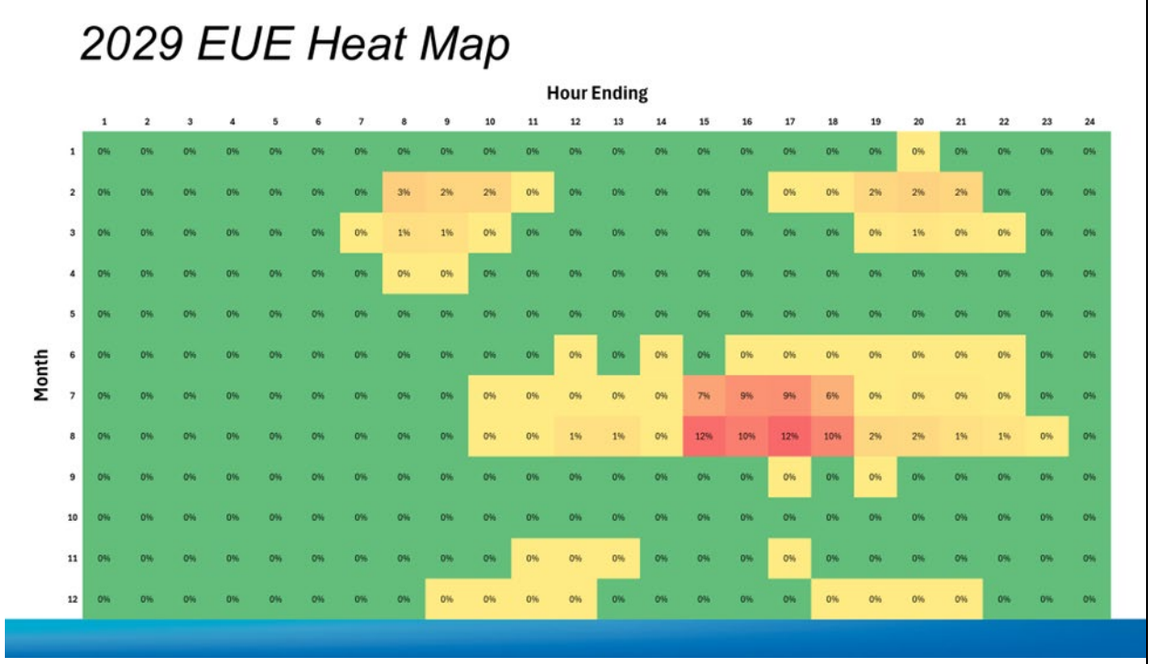
Energy Risk
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific 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.

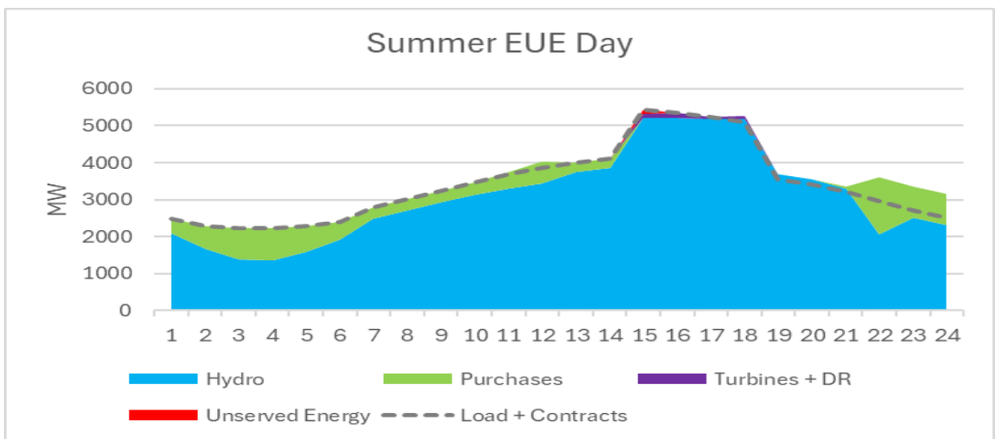
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

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.



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.

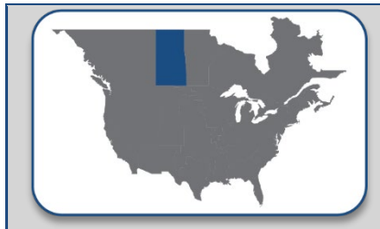
Energy Transfers

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.

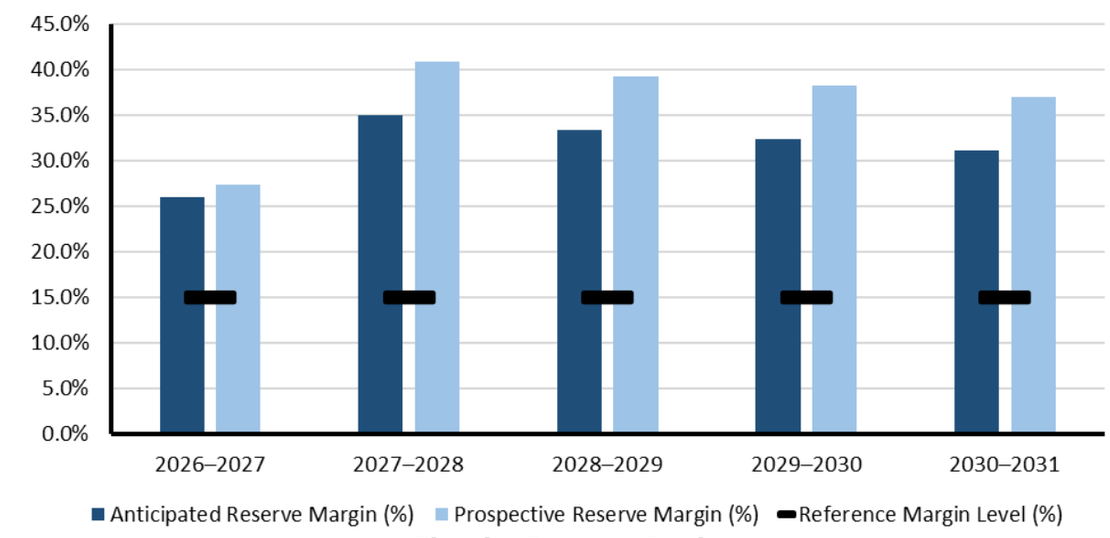


MRO-SaskPower

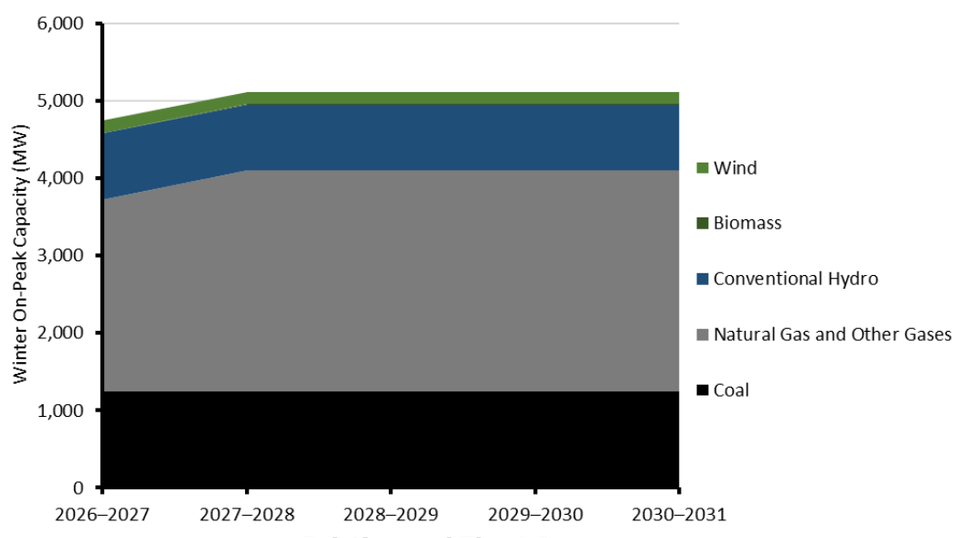
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator 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.

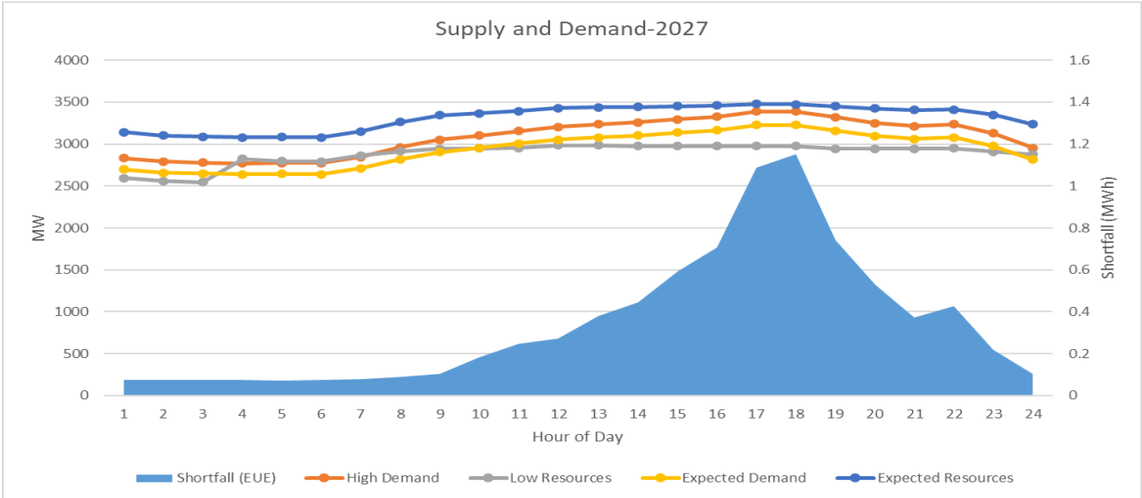
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
*** Provides the 2024 ProbA Results for Comparison**			

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%	1%	1%	1%	0%	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%	1%	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.

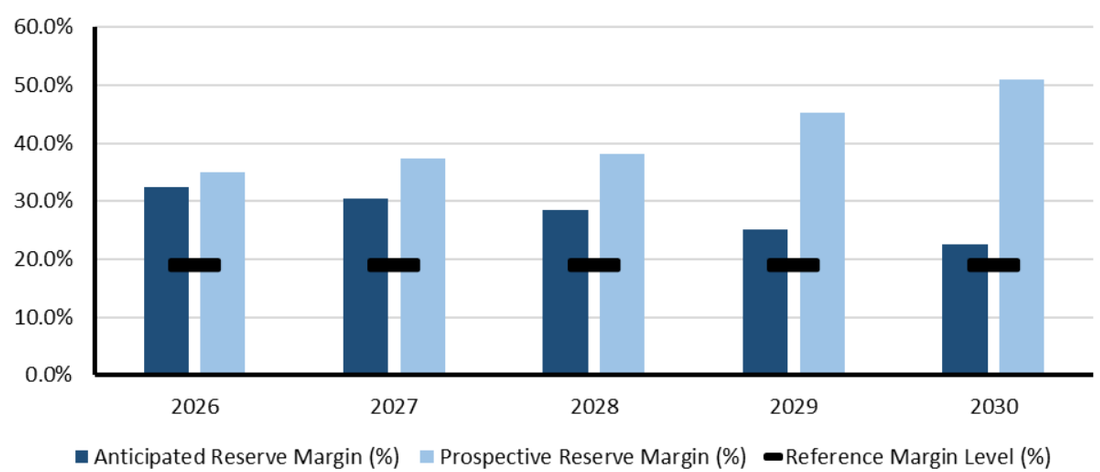
SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

MRO-SPP

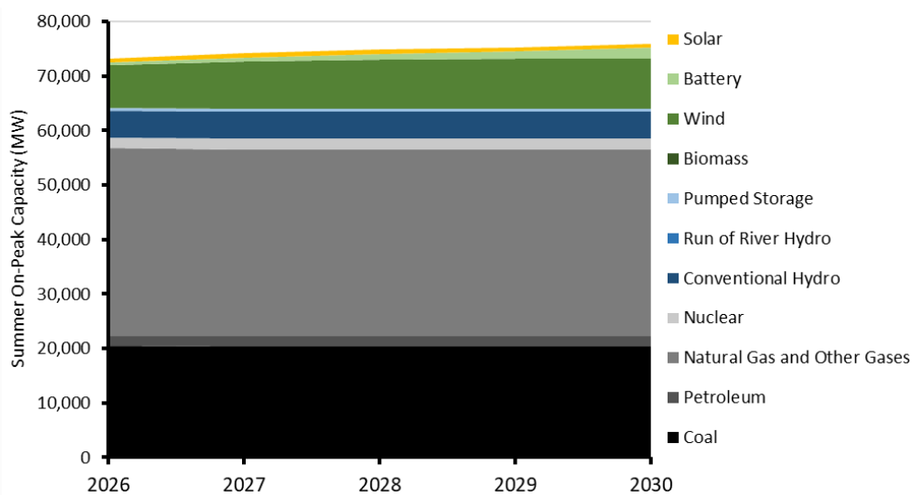
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the 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.

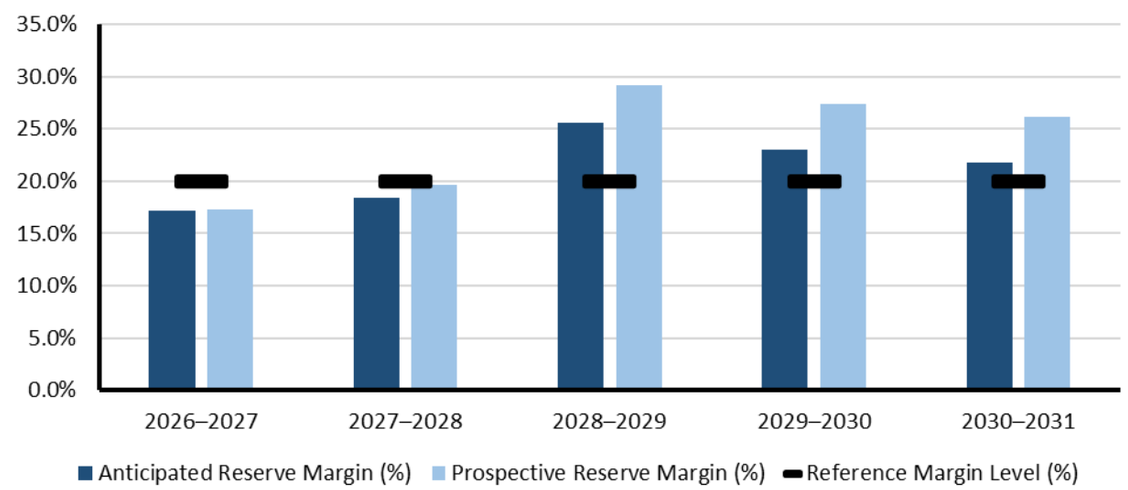
Transmission
SPP's 2024 Integrated Transmission Plan (ITP) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

NPCC-Maritimes

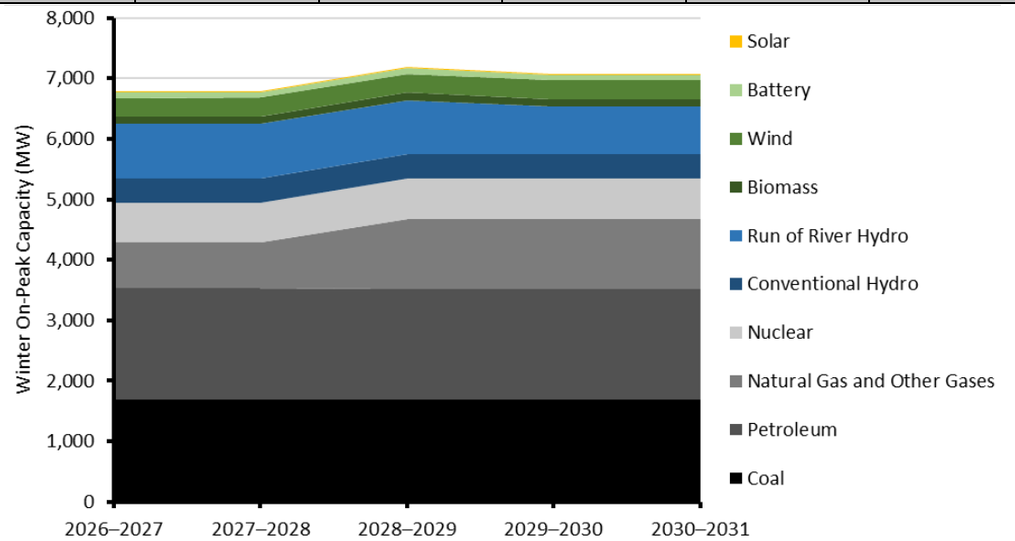
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 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 (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.

[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 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.

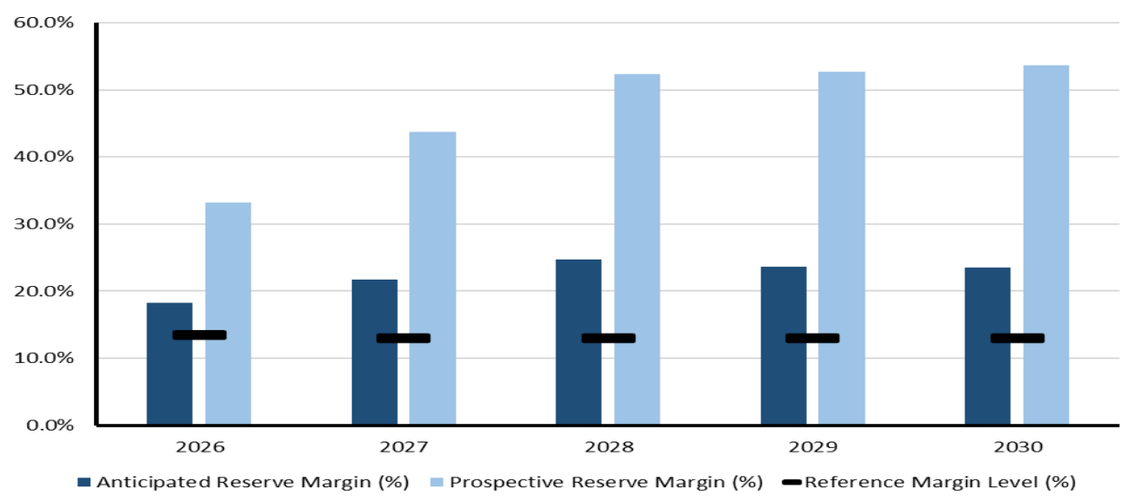
NPCC-New England

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.

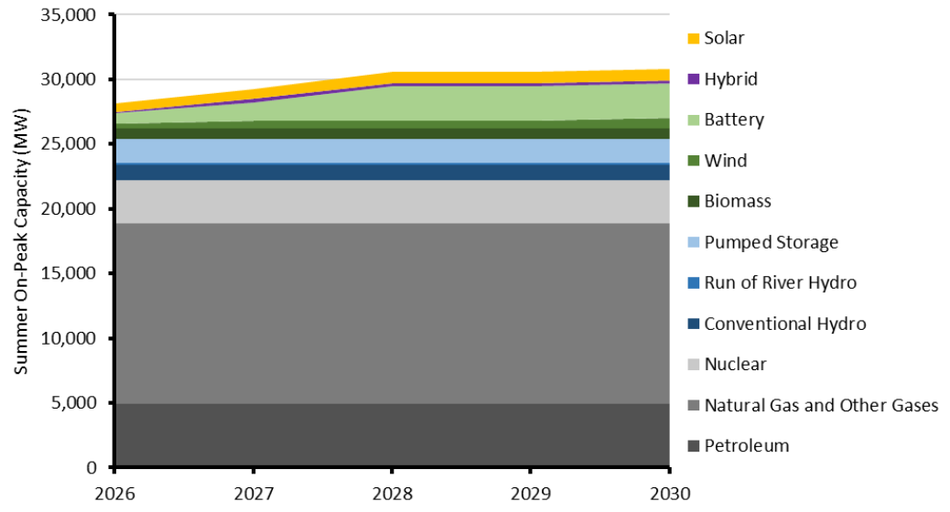
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

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.

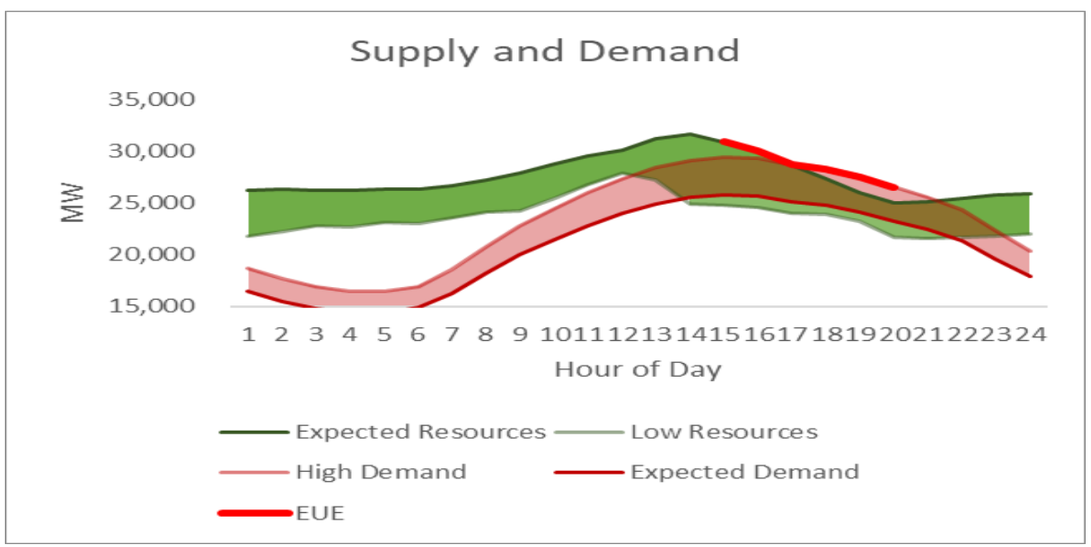
NPCC New England Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

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%	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%	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%

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:

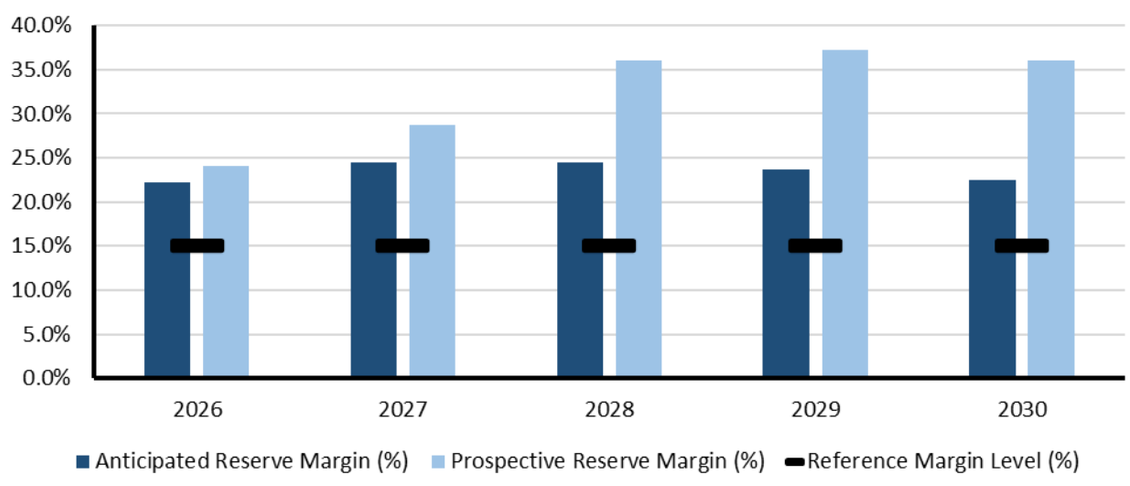
- Capacity Auction Reforms
- Operational Impacts of Extreme Weather Events
- Day-Ahead Ancillary Services Initiative
- 2024 Economic Study
- Extended-Term Transmission Planning Tariff Changes (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- Longer-Term Transmission Studies
- Storage As Transmission Only Asset
- FERC Order No. 1920 Project
- FERC Order No. 2023 Project
- FERC Order No. 2222 Project

NPCC-New York

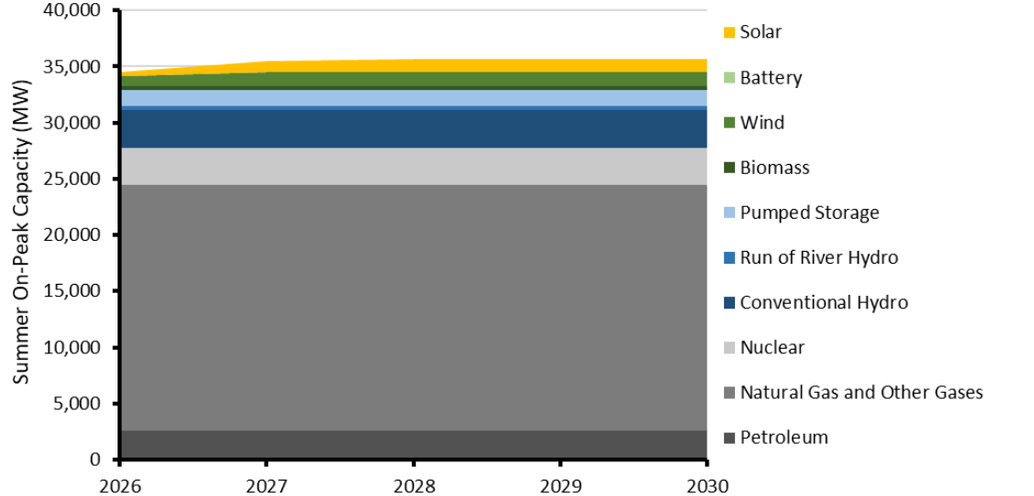
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 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 (DEFR) 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

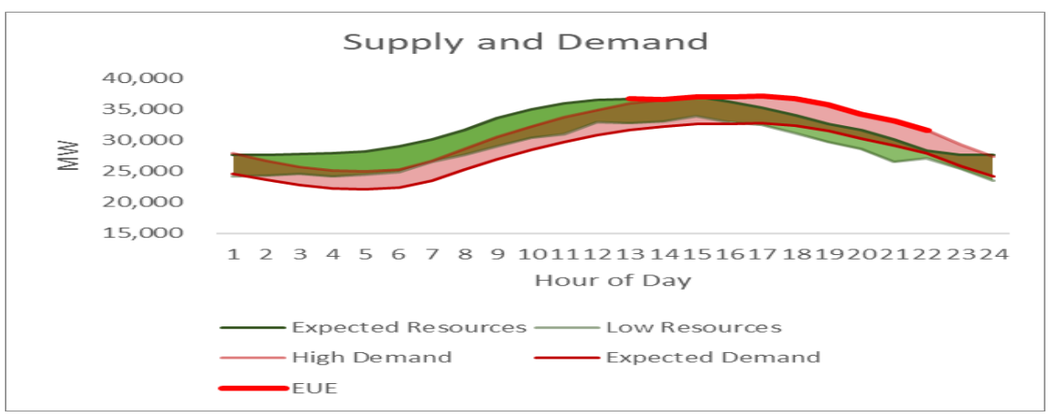
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

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%	1%	7%	24%	25%	7%	3%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	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 process[41] 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.

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 DEFRs, 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.

[41] https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

[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.

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 analysis[44] 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 report[45] 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.

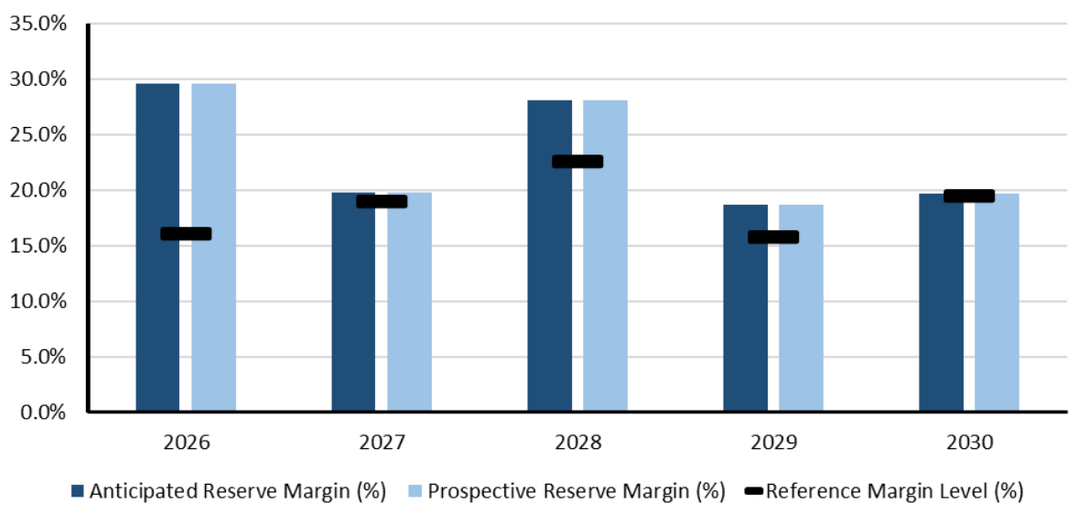
[43] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf
[44] https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
[45] NYISO's 2025 Q3 STAR Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf and Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

NPCC-Ontario

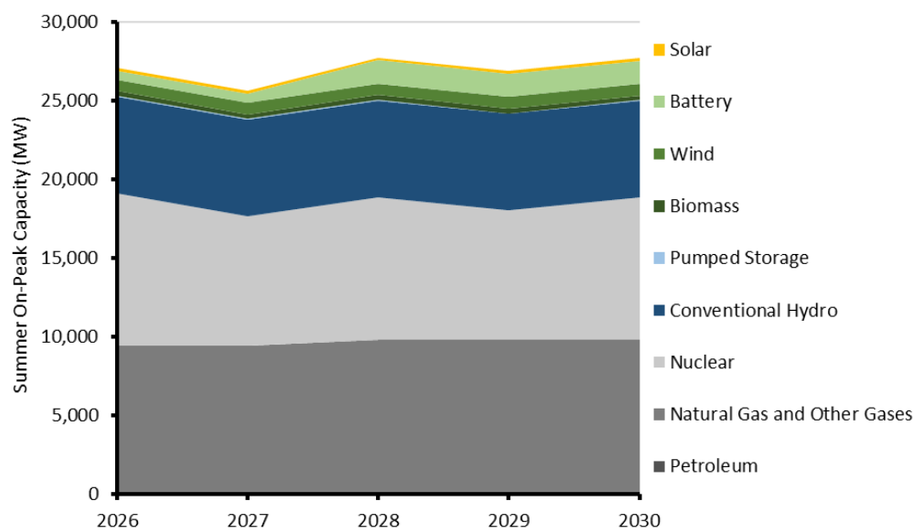
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for 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.

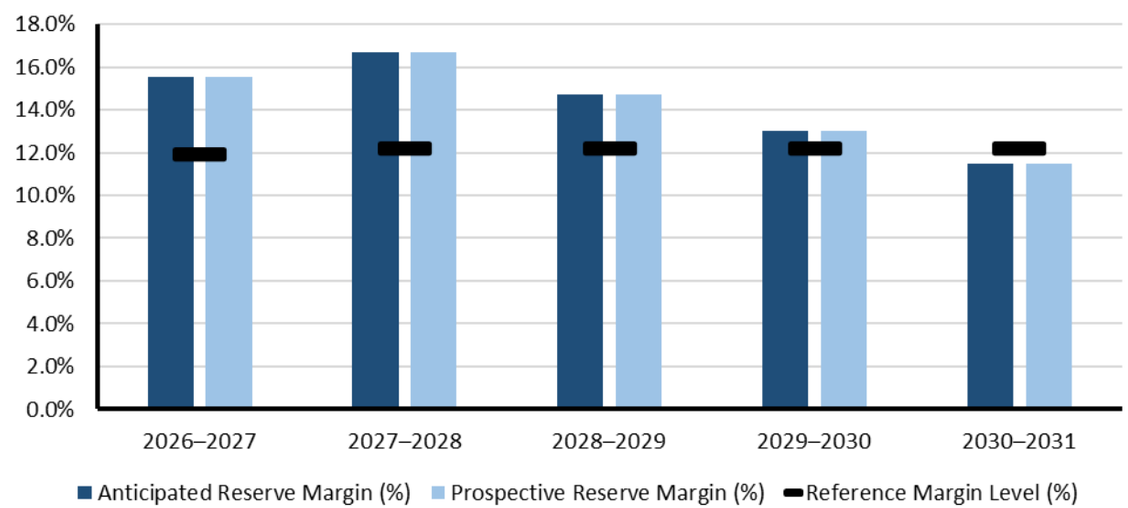
Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery 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

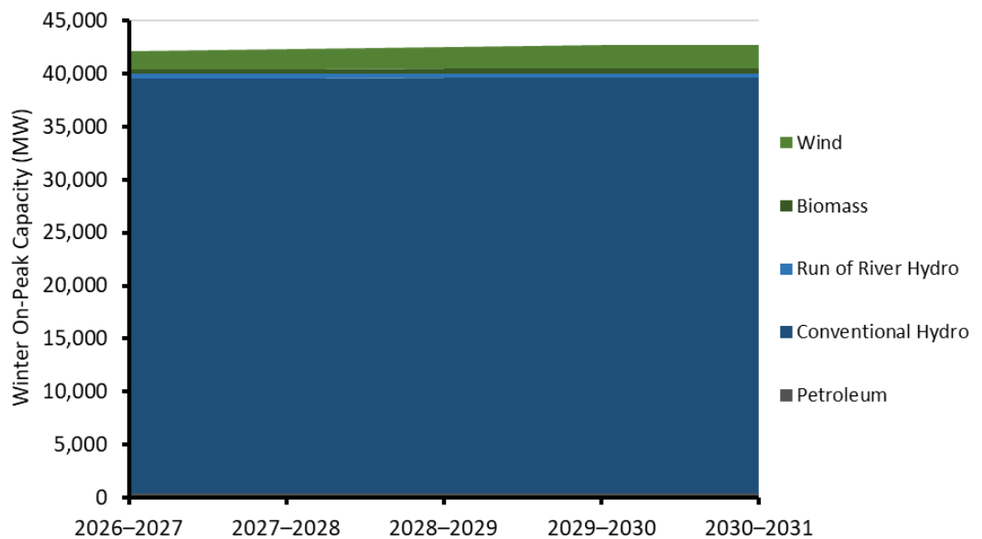
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the 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.

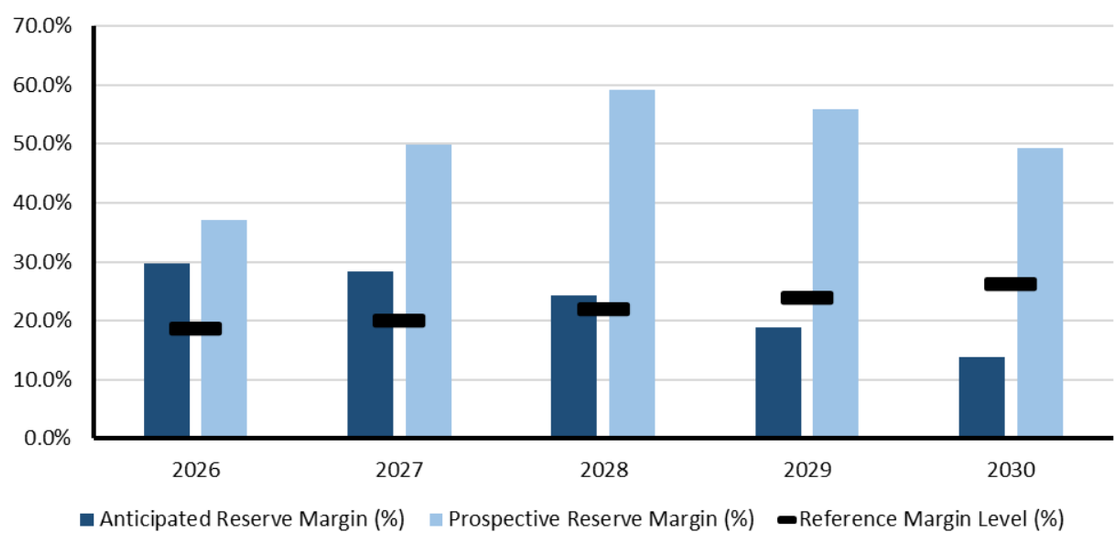
Reliability Issues
Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected 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

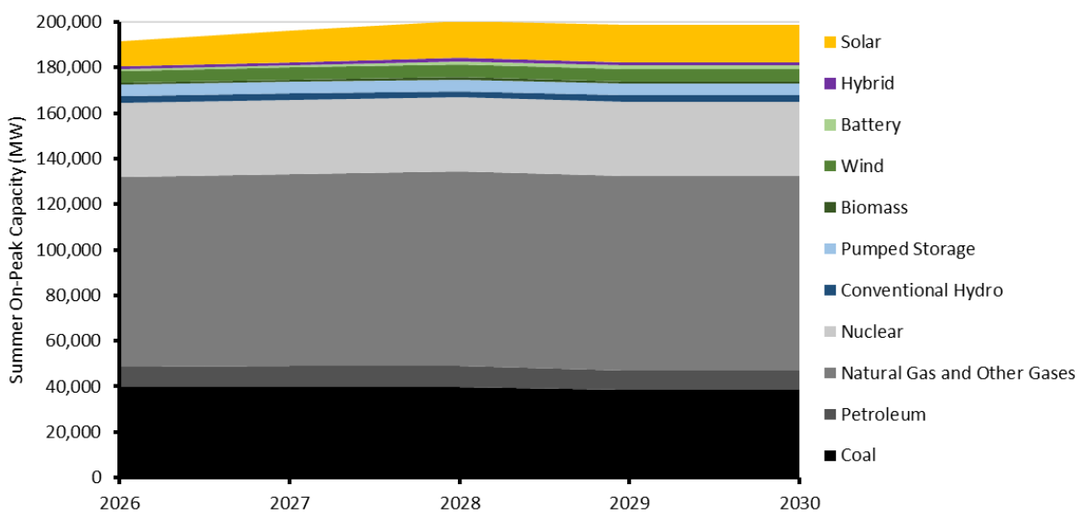
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. 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 202**4 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.

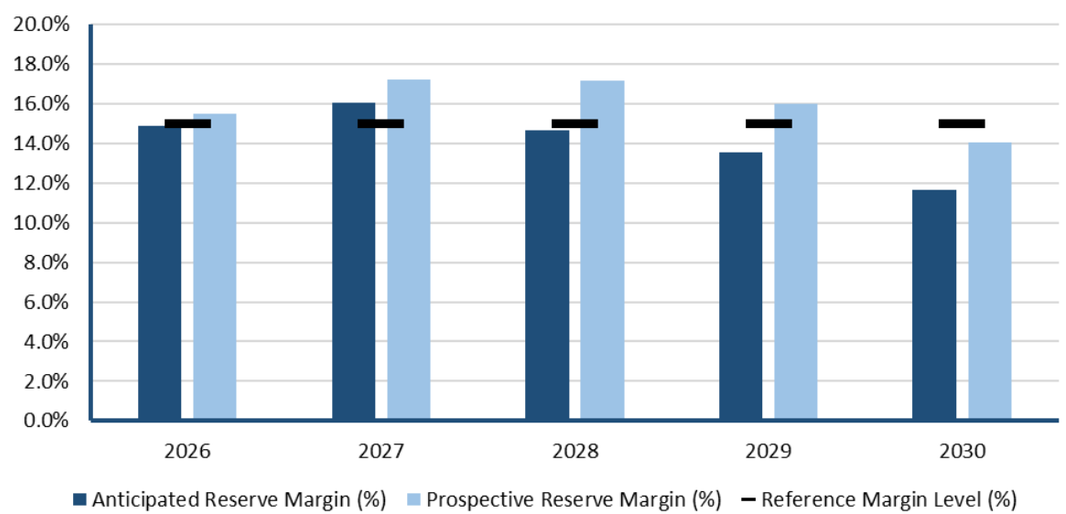
From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved $5.9 billion worth of regional and local projects to address the reliability criteria violations.

SERC-Central

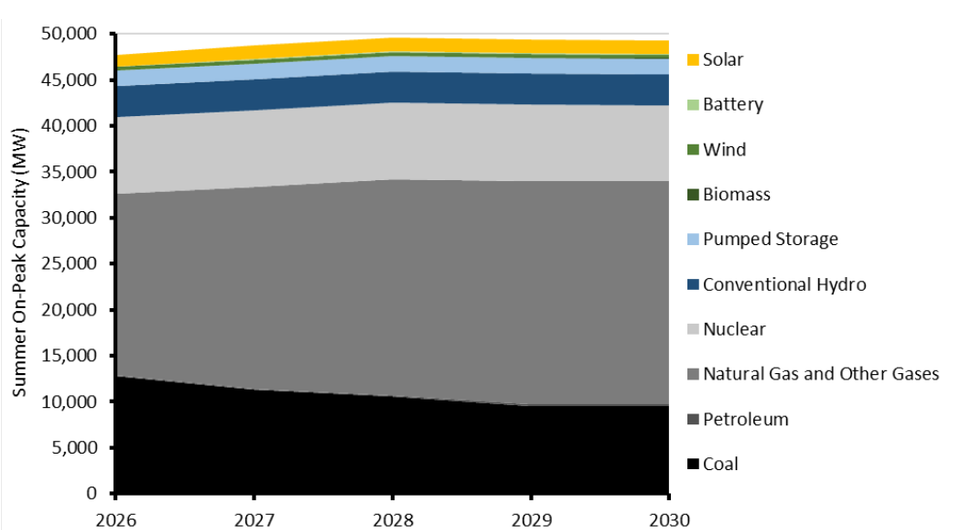
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of 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.

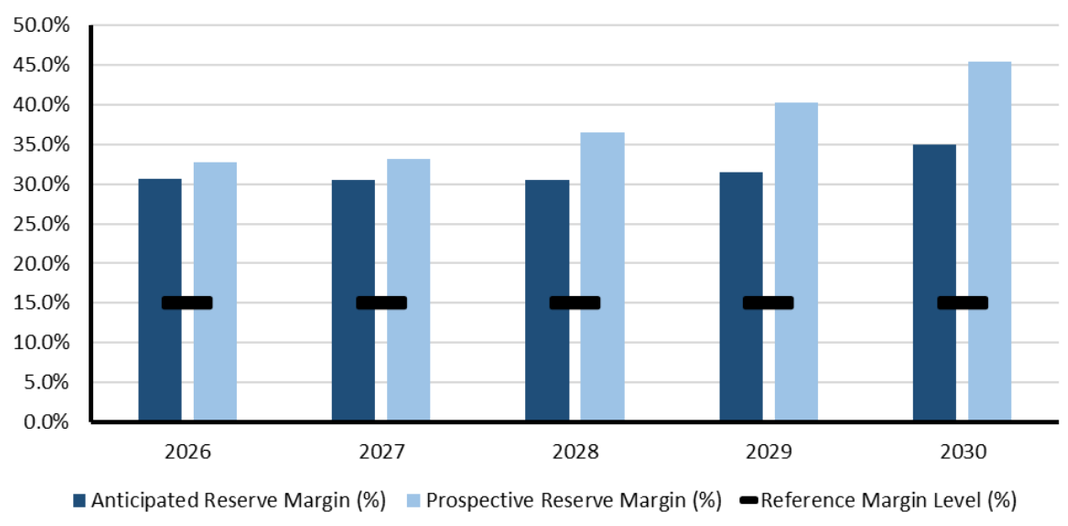
- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While 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

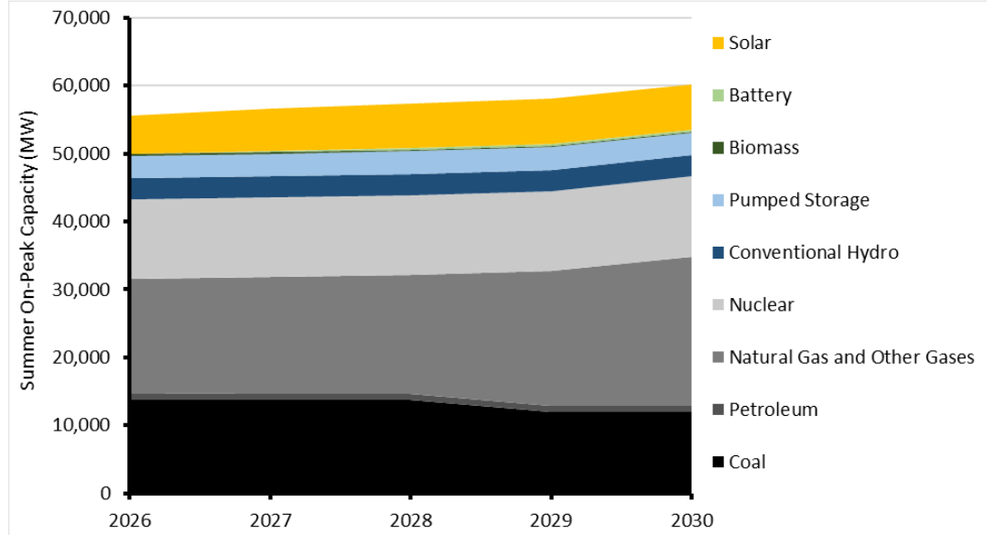
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible 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:

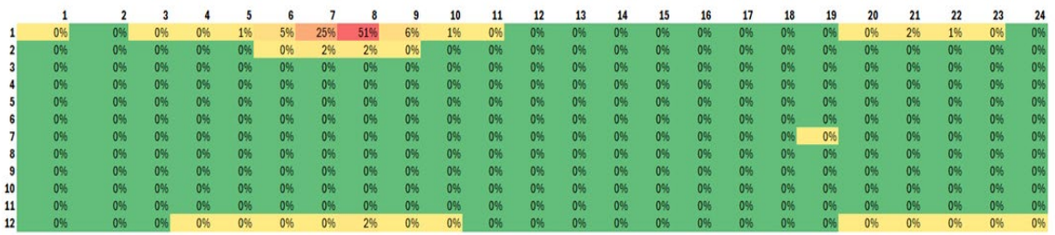
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also 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

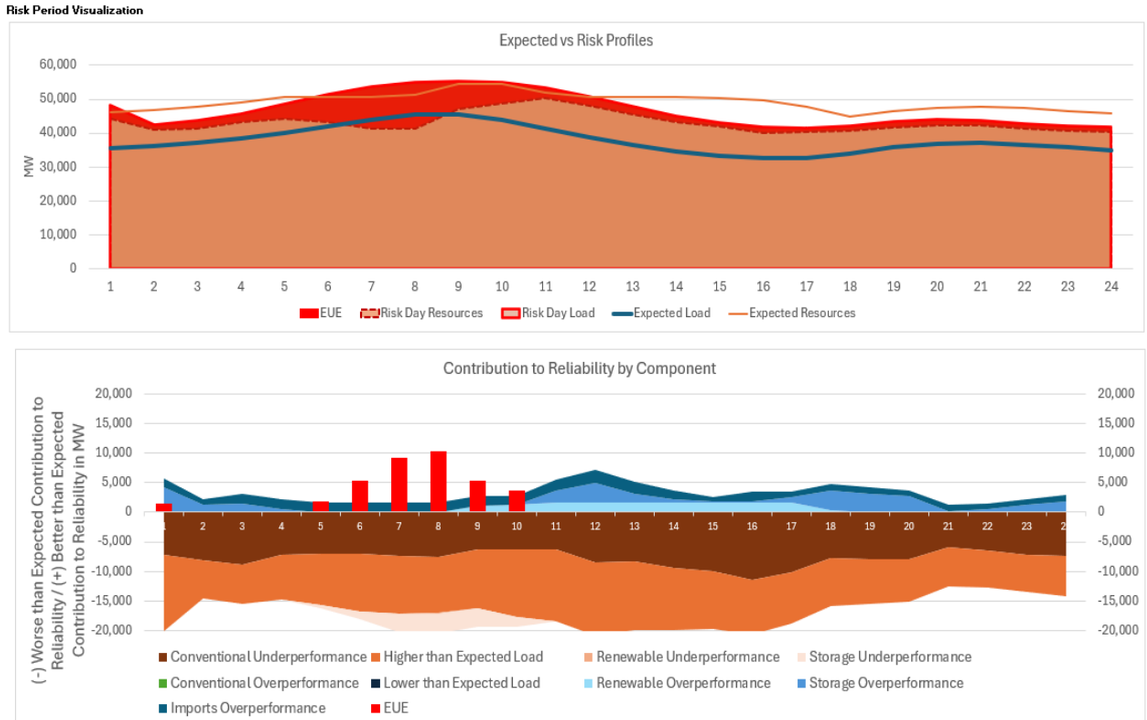
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	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%	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, the 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

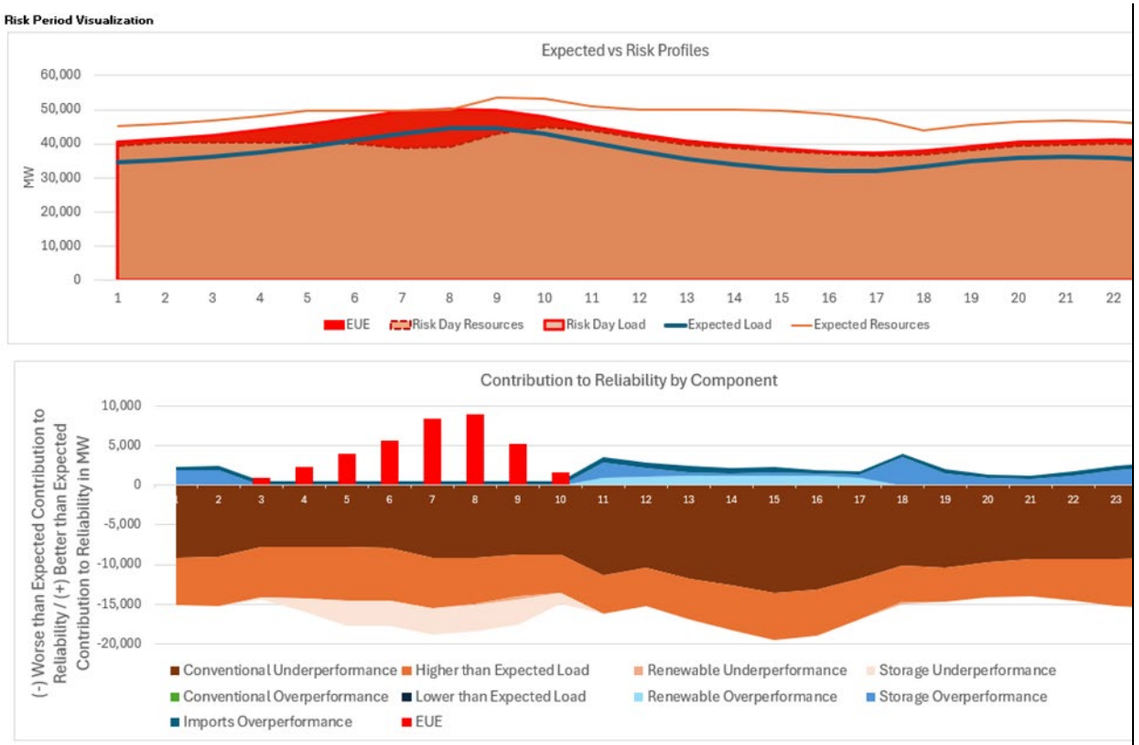
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



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).



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.

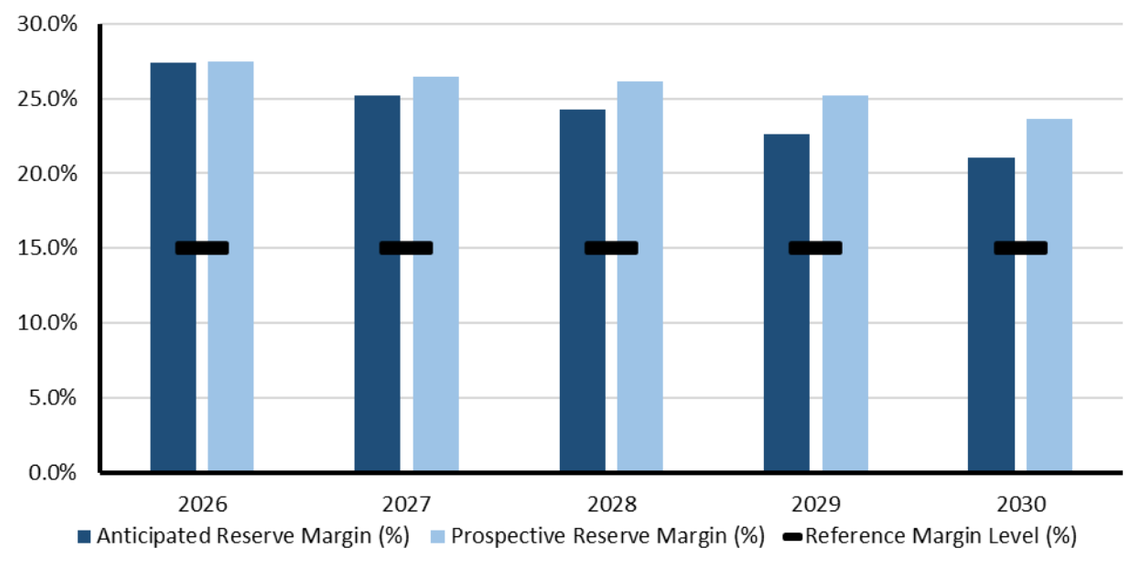
Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages 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

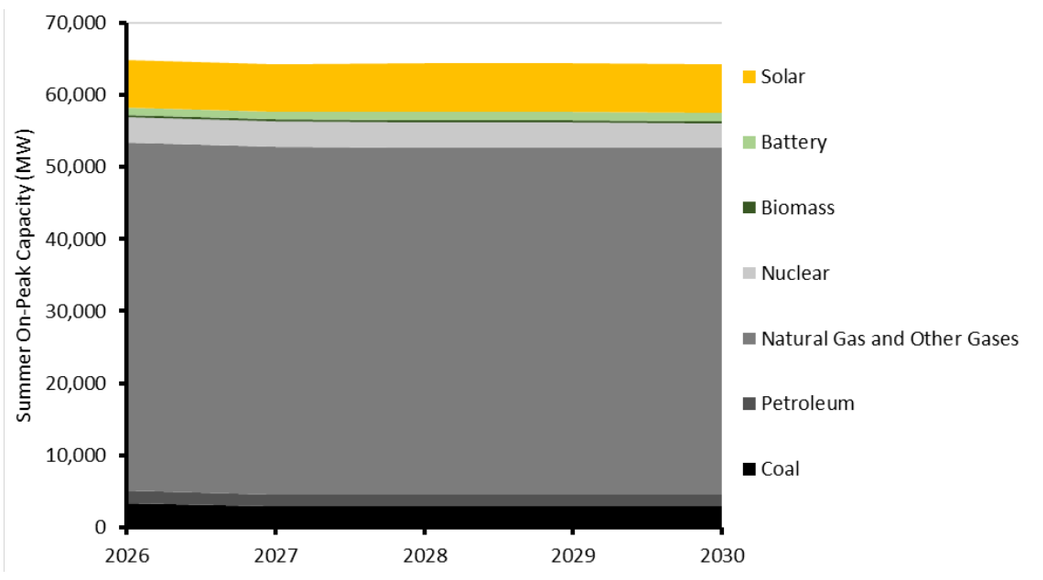
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across 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 SERVM 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.

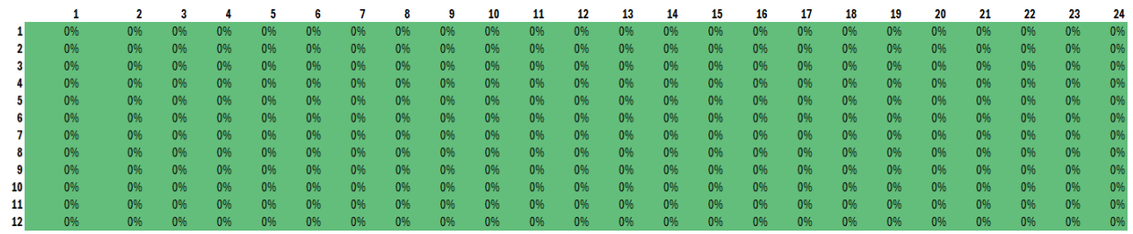
These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. 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.

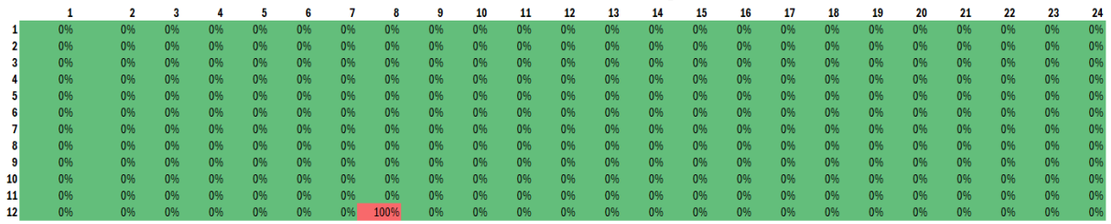
ProbA Results

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			



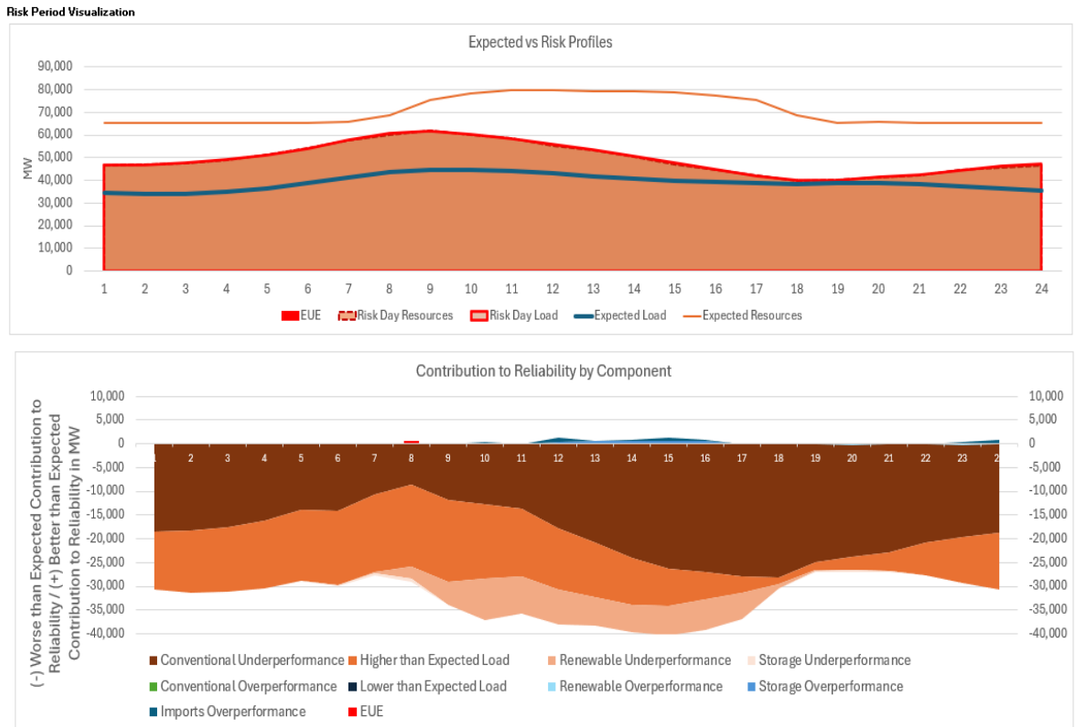
2027 EUE Heat Map



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:

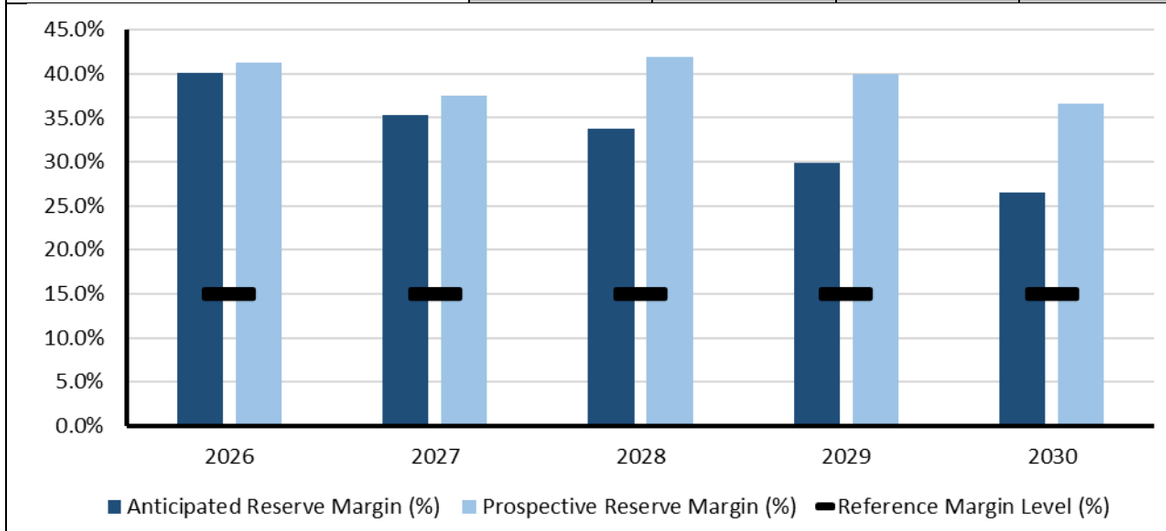
- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are "not considered significant in the near-term" for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and 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

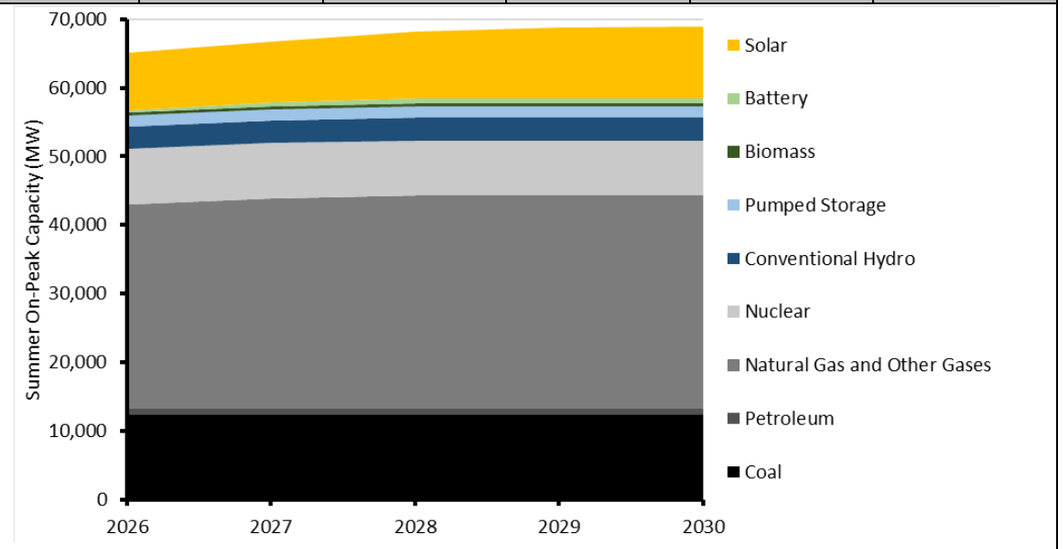
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. 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.					

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%

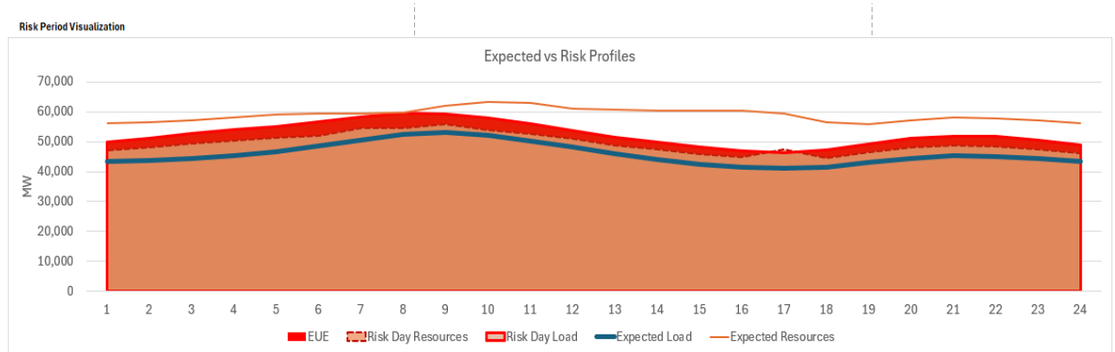
2027 EUE Heat Map

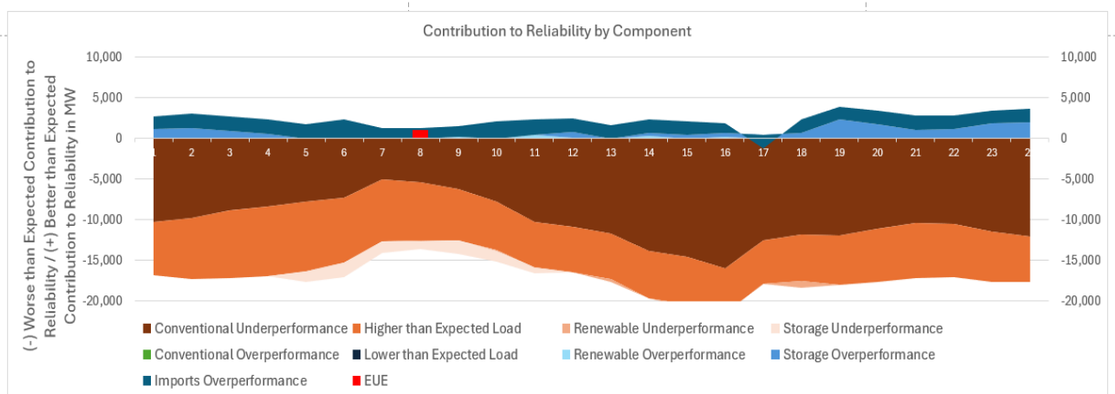
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events 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%	22%	0%

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:

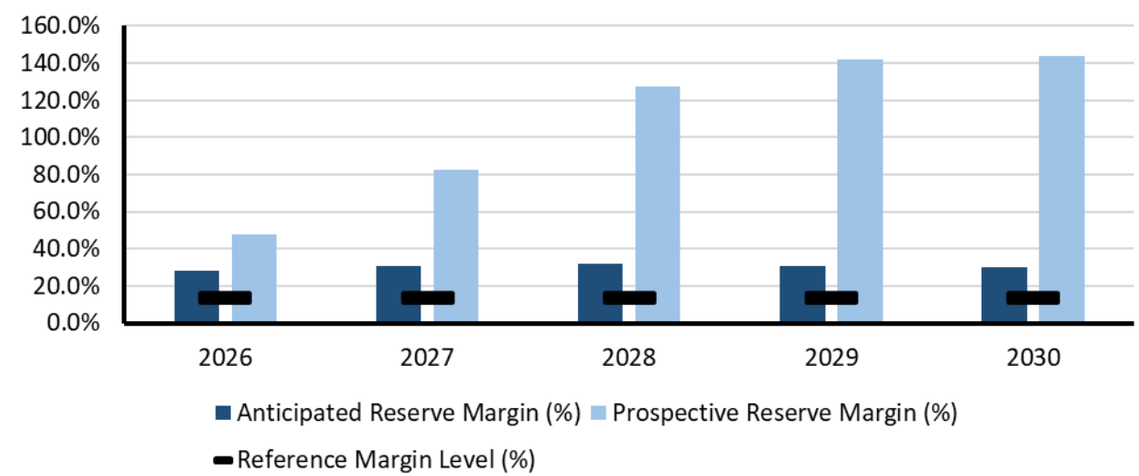
- **Elevated Winter Energy Risk and Sustained Overnight Loads**: Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, 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

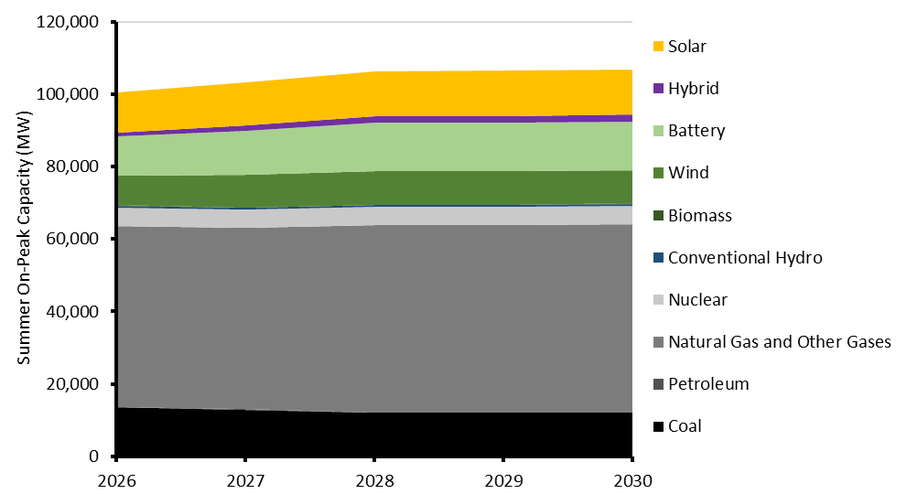
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million 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.

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%	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%	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%	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%	0%	1%	2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	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%	1%	1%	3%	2%	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.

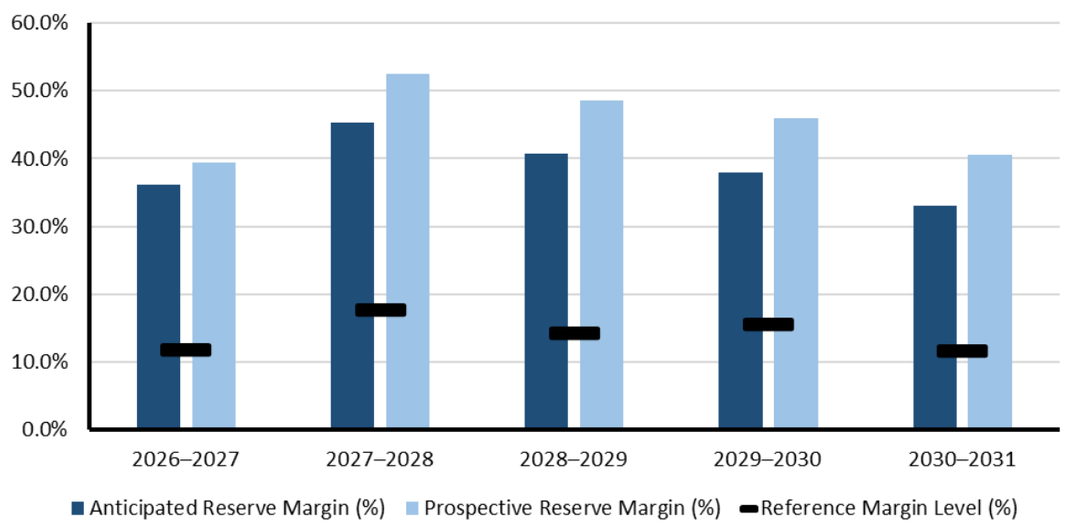
Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

WECC-Alberta

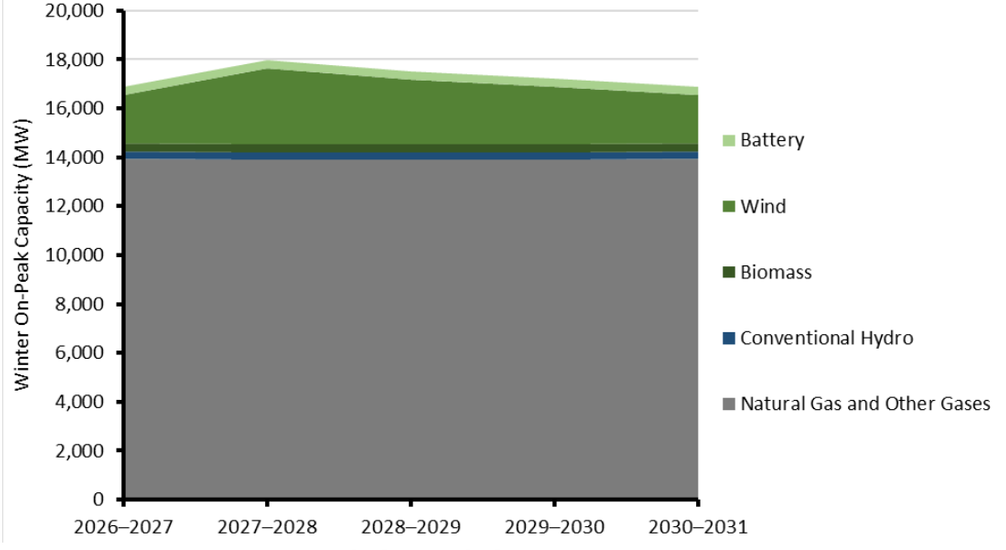
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability 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.

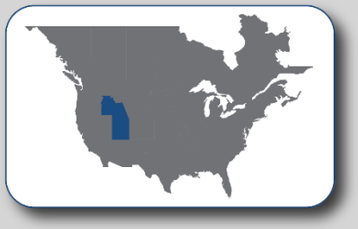
Energy Transfers

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.

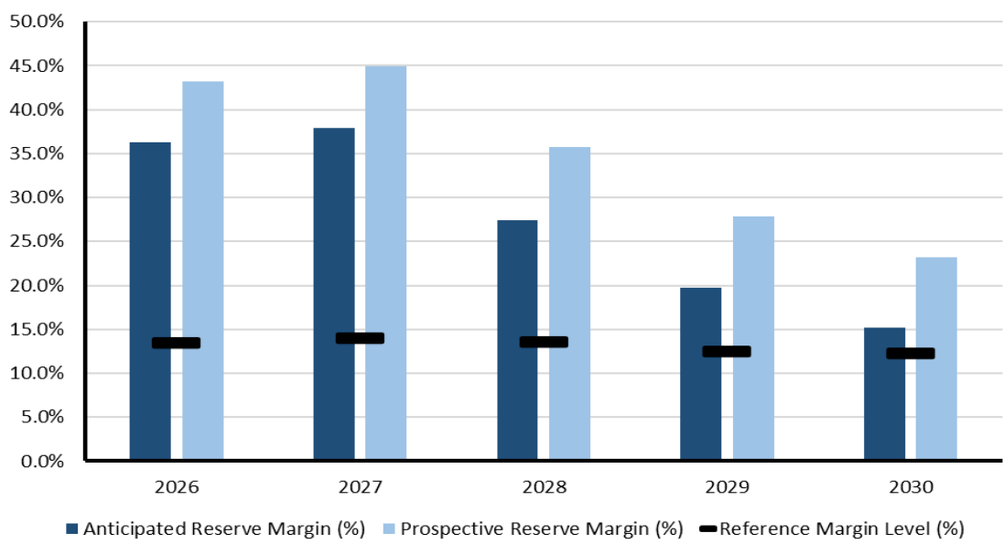


WECC-Basin

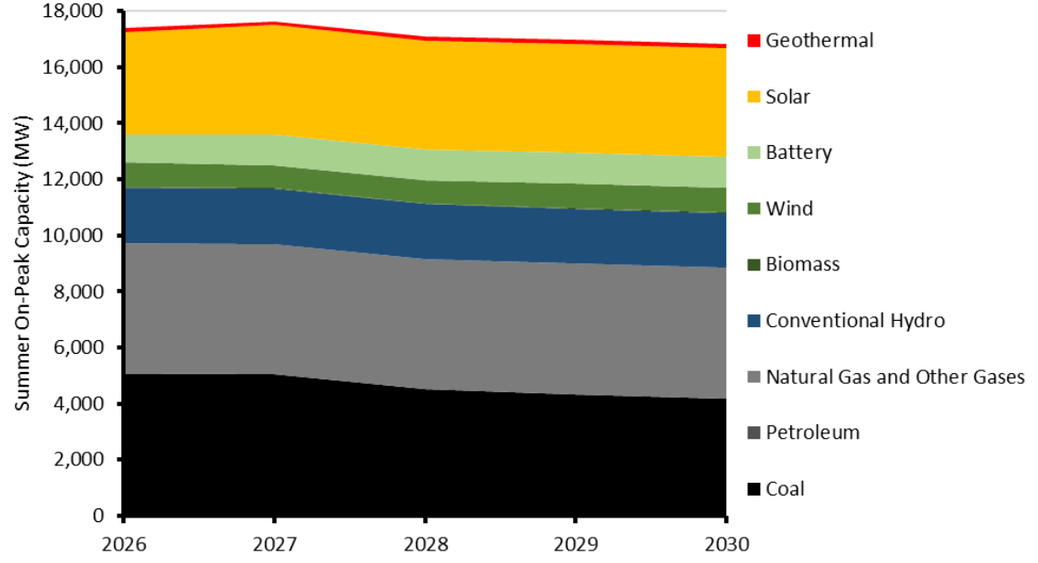
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is 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.

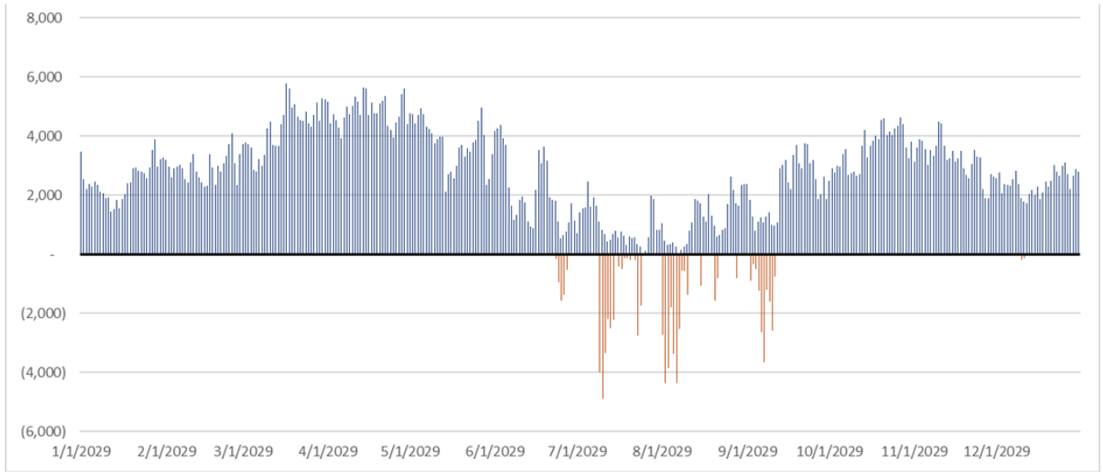
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
*** No prior results as the assessment area is new for the 2025 LTRA.**			

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.

Basin - 2027		Months												Basin - 2029		Months											
Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning	0	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning	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		1	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		2	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		3	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		4	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		5	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		6	0	0	0	0	0	0	0	0	0	0	0	1
	7	0	0	0	0	0	0	0	0	0	0	0	0		7	0	0	0	0	0	0	0	1	0	0	0	2
	8	0	0	0	0	0	0	0	0	0	0	0	0		8	0	0	0	0	0	0	0	1	0	0	0	2
	9	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
	10	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
	11	0	0	0	0	0	0	0	0	0	0	0	0		11	0	0	0	0	0	0	2	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0		12	0	0	0	0	0	0	8	1	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0		13	0	0	0	0	0	1	9	2	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0		14	0	0	0	0	0	2	8	2	1	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0		15	0	0	0	0	0	3	8	3	1	0	0	0
	16	0	0	0	0	0	0	0	0	0	0	0	0		16	0	0	0	0	0	2	8	4	6	0	0	3
	17	0	0	0	0	0	0	0	0	0	0	0	0		17	2	0	0	0	0	4	11	14	8	0	0	5
	18	0	0	0	0	0	1	0	0	0	0	0	0		18	0	0	0	0	0	6	16	20	12	0	0	4
	19	0	0	0	0	0	1	1	0	0	0	0	0		19	0	0	0	0	0	7	17	22	9	0	0	3
	20	0	0	0	0	0	0	0	0	0	0	0	0		20	0	0	0	0	0	5	16	13	8	0	0	2
	21	0	0	0	0	0	0	0	0	0	0	0	0		21	0	0	0	0	0	0	7	9	1	0	0	0
	22	0	0	0	0	0	0	0	0	0	0	0	0		22	0	0	0	0	0	0	0	5	0	0	0	0
	23	0	0	0	0	0	0	0	0	0	0	0	0		23	0	0	0	0	0	0	0	3	0	0	0	0

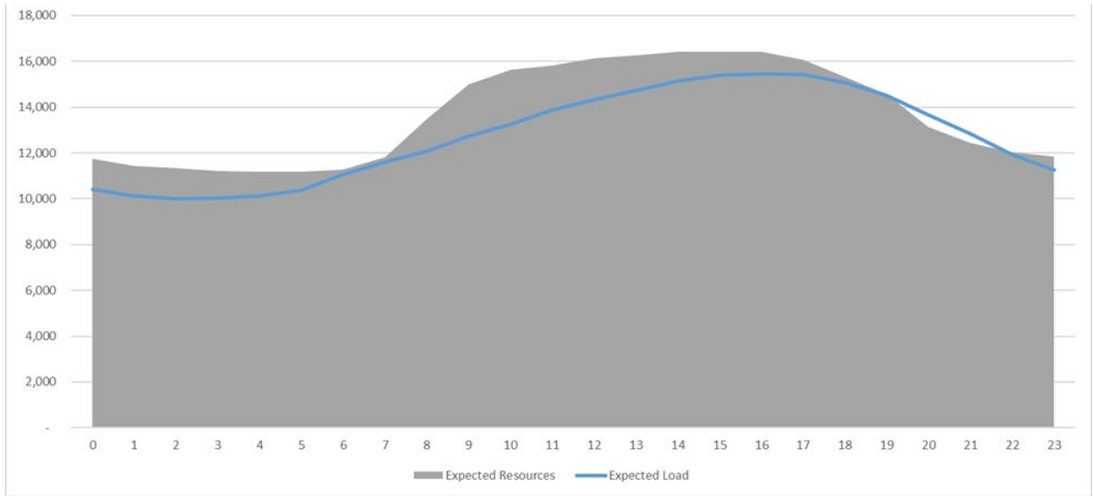
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

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.

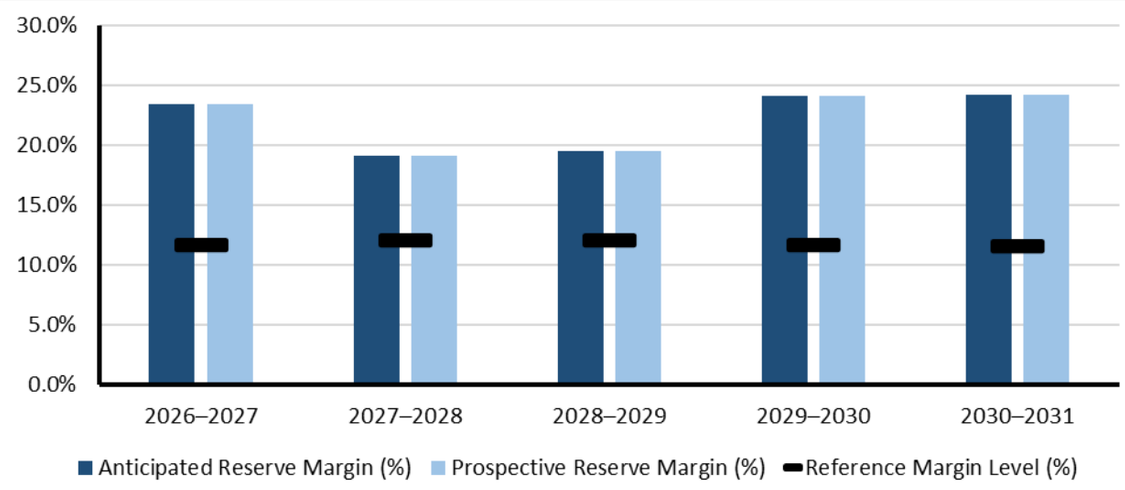
The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned 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

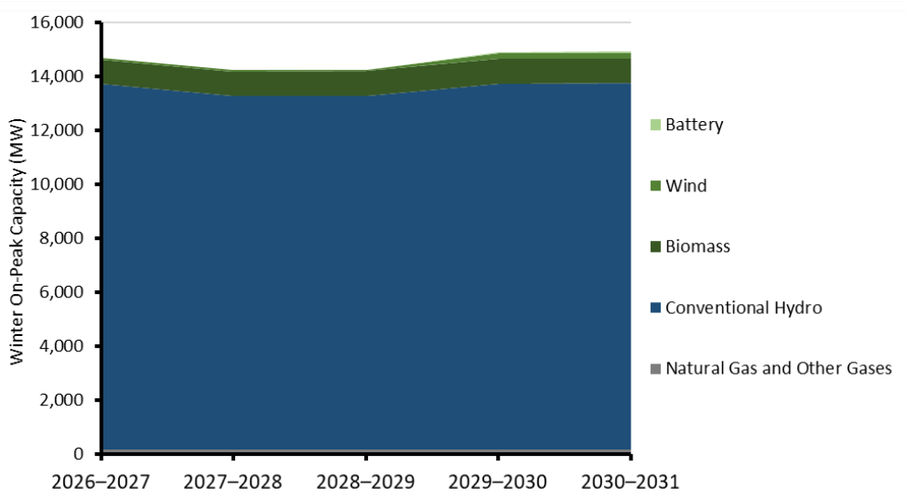
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the 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 Highlights

- 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

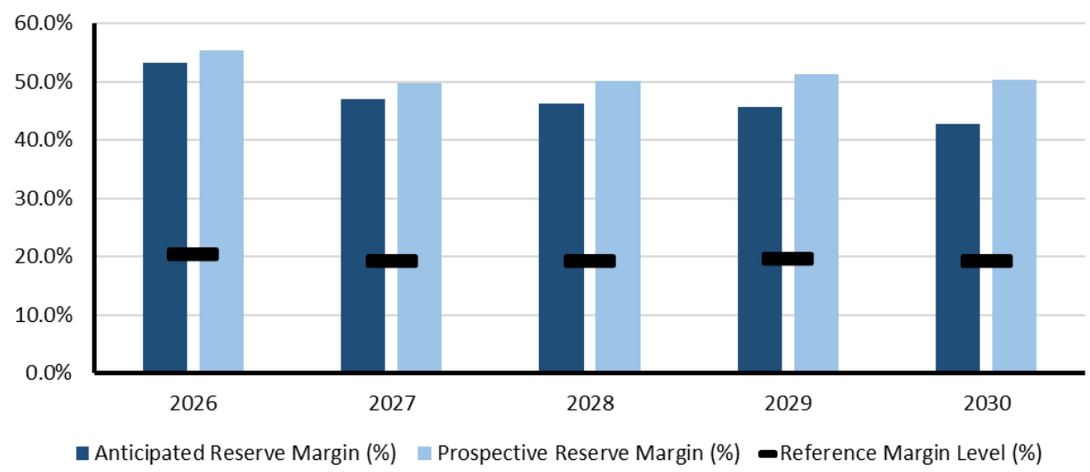
Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in 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

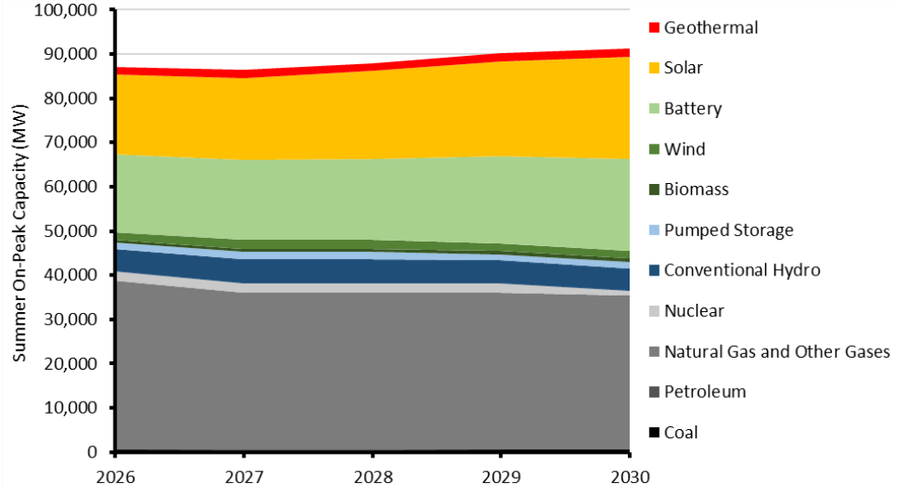
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock 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

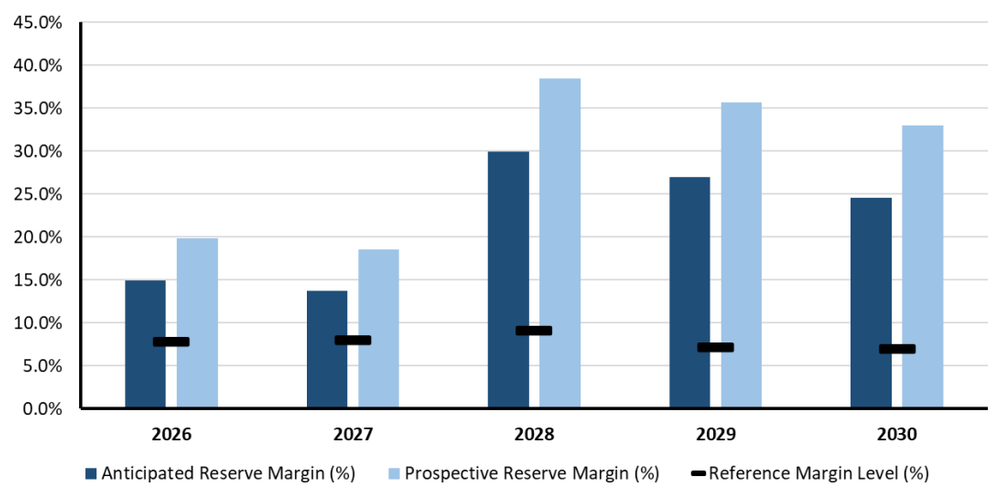
The ITCS report showed that in a heat wave Northern California may be energy-deficient.

WECC-Mexico

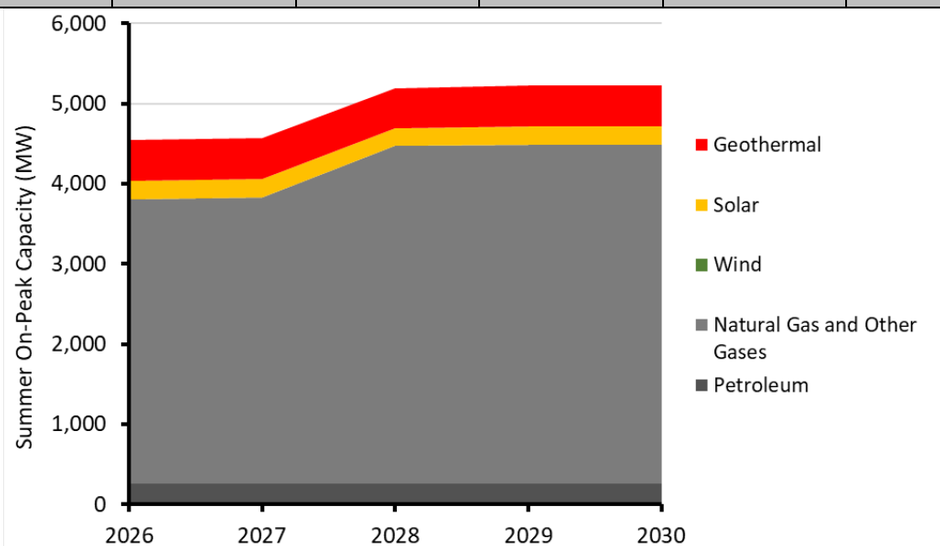
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting 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:

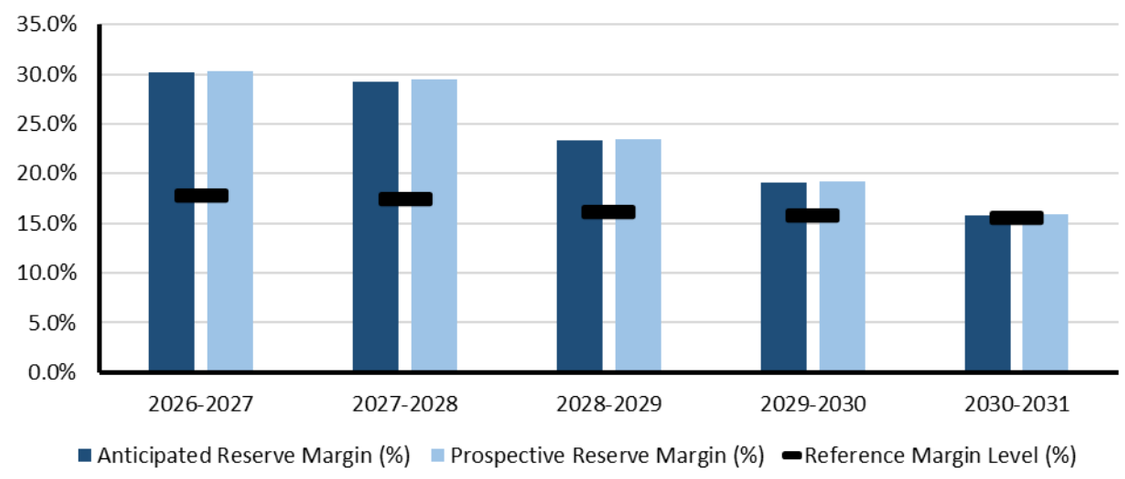
- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand 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

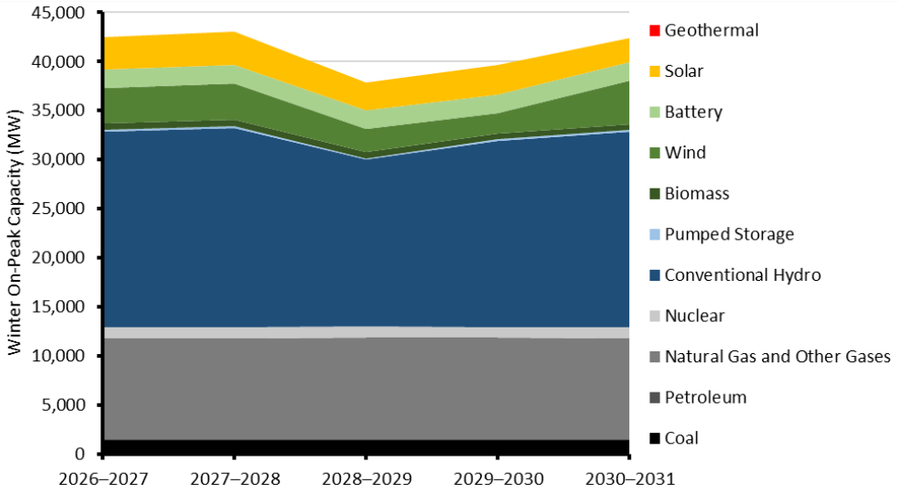
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for 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

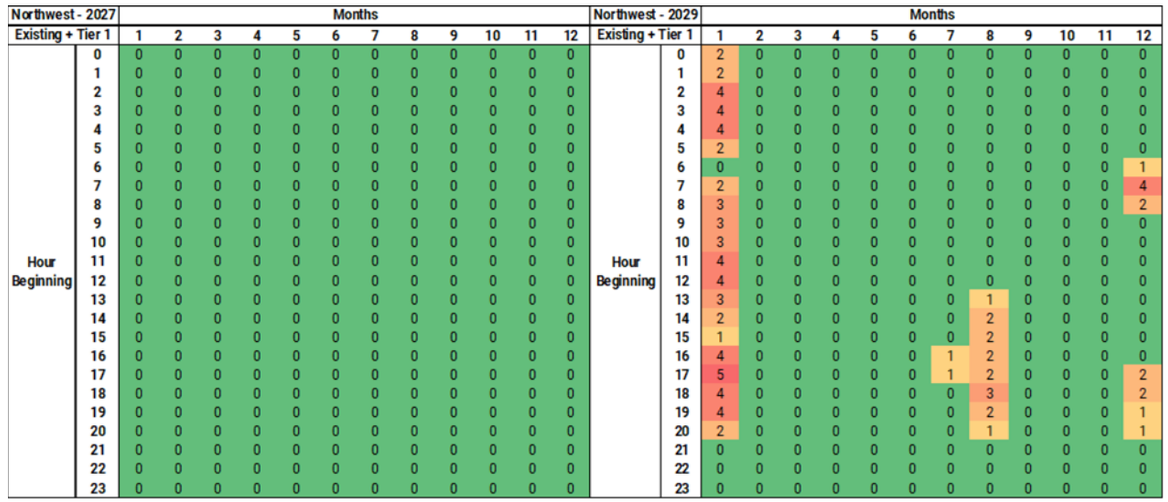
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

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.			

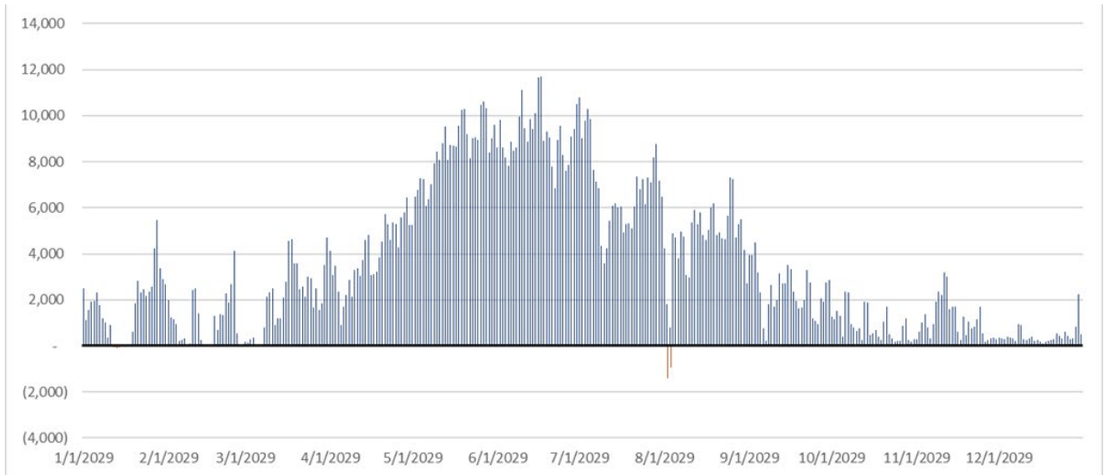
Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also 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.



Northwest - 2027	Months												Northwest - 2029	Months										
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
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
1	0	0	0	0	0	0	0	0	0	0	0	0	1	2	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	2	4	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	3	4	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	5	2	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	1
7	0	0	0	0	0	0	0	0	0	0	0	0	7	2	0	0	0	0	0	0	0	0	0	0	4
8	0	0	0	0	0	0	0	0	0	0	0	0	8	3	0	0	0	0	0	0	0	0	0	0	2
9	0	0	0	0	0	0	0	0	0	0	0	0	9	3	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	10	3	0	0	0	0	0	0	0	0	0	0	0
Hour Beginning 11	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning 11	4	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	12	4	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	13	3	0	0	0	0	0	0	1	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0	14	2	0	0	0	0	0	0	2	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	15	1	0	0	0	0	0	0	2	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0	16	4	0	0	0	0	0	1	2	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0	17	5	0	0	0	0	0	1	2	0	0	0	2
18	0	0	0	0	0	0	0	0	0	0	0	0	18	4	0	0	0	0	0	0	3	0	0	0	2
19	0	0	0	0	0	0	0	0	0	0	0	0	19	4	0	0	0	0	0	0	2	0	0	0	1
20	0	0	0	0	0	0	0	0	0	0	0	0	20	2	0	0	0	0	0	0	1	0	0	0	1
21	0	0	0	0	0	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	0	0	0	0	0

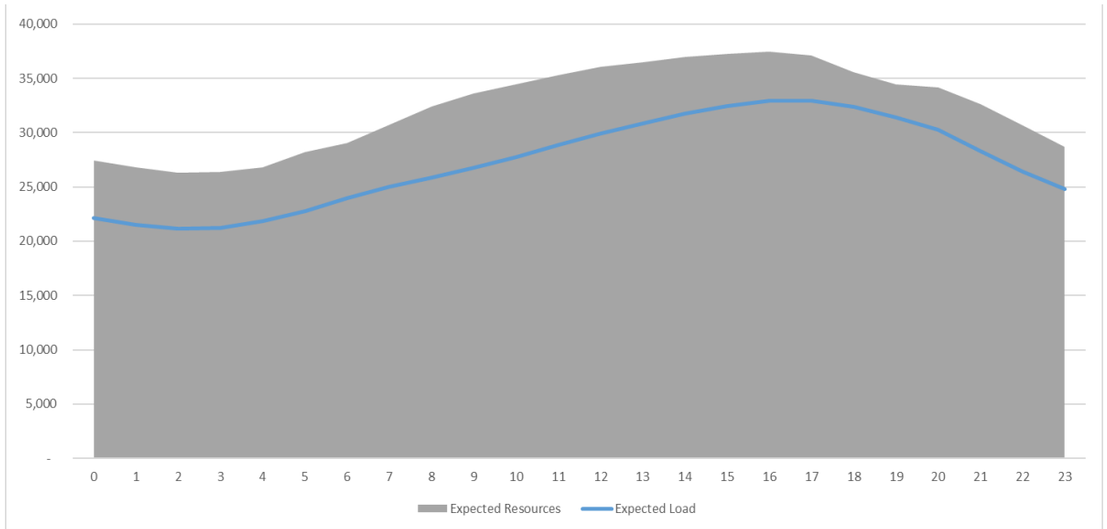
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

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.

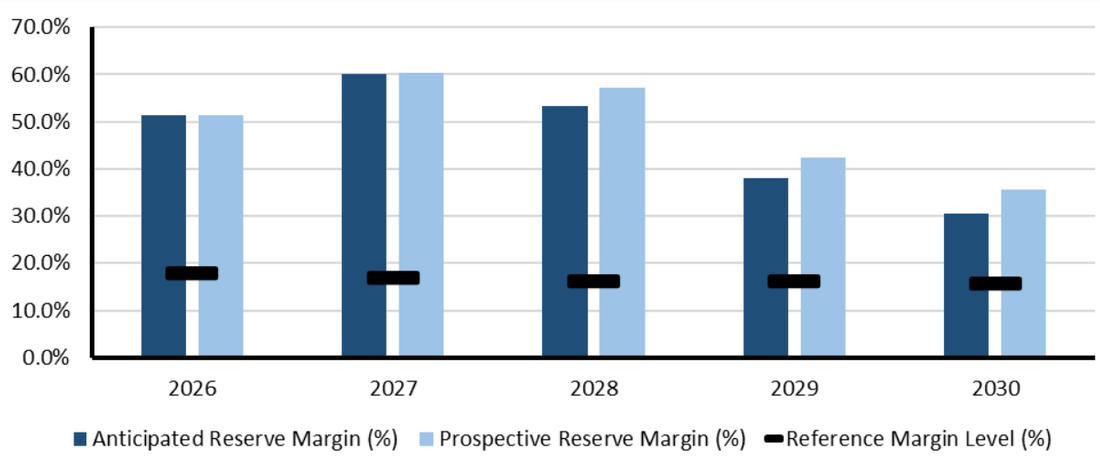
Transmission: PacifiCorp's Blueprint transmission project will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be 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

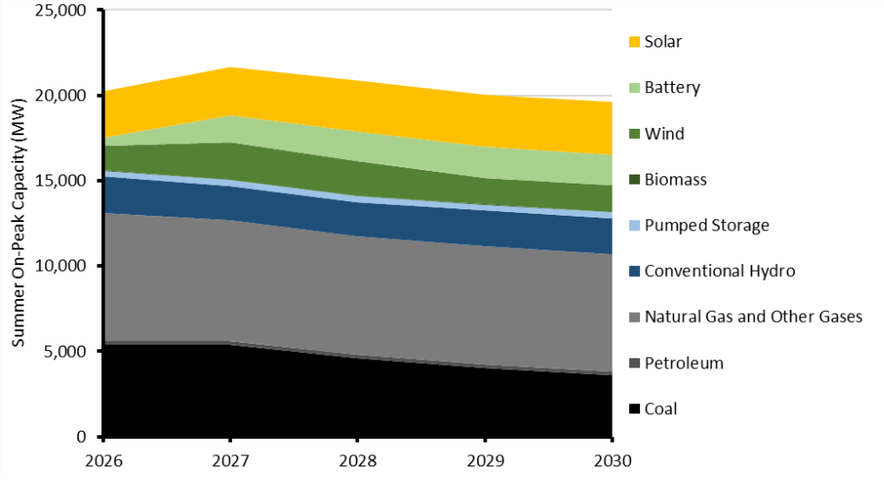
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and 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.

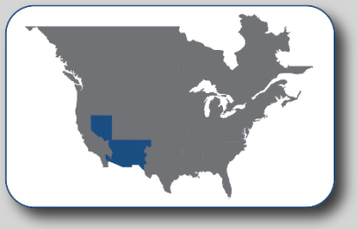
Demand-Side Management
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

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.

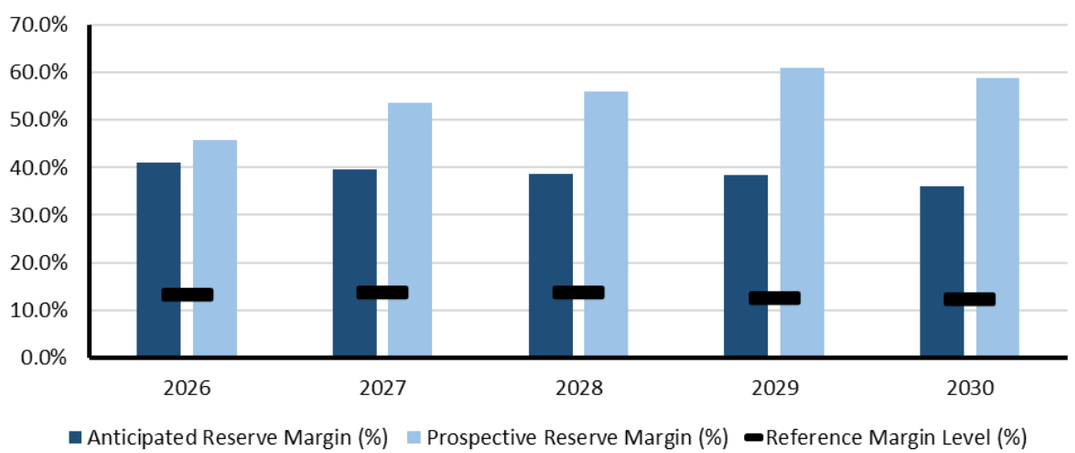


WECC-Southwest

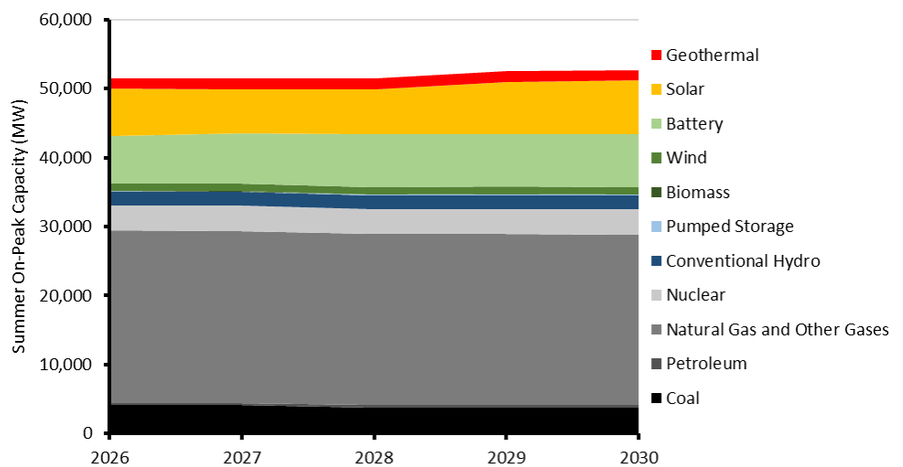
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for 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 Resources[53]

- 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 retirements[54]

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 is 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 curtailment[58]
- 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.

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
Cold Weather Reliability Standards and Activities	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. Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States* 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 fillings 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.	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	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 *IBR Activities Reference Guide*.[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. 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.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[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		
	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.	
Natural Gas-Electric Interdependence Initiatives	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 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]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 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.		
Initiative	**Description**	**Product/Reliability Solution**
***Interregional Transfer Capability Study* (ITCS)**	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024[85]. 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**.	ERO Study and Recommendations

[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

LTRA Recommendations and Ongoing ERO Actions

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

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2025 LTRA* 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. 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. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[90] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* 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]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	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 *DER Activities Reference Guide*.[92]	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	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.	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)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Orlando Utilities Commission Regarding the Stanton Energy Center	Order No. 202-26-26

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

EXHIBIT 15

2026 SRA

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

Table of Contents

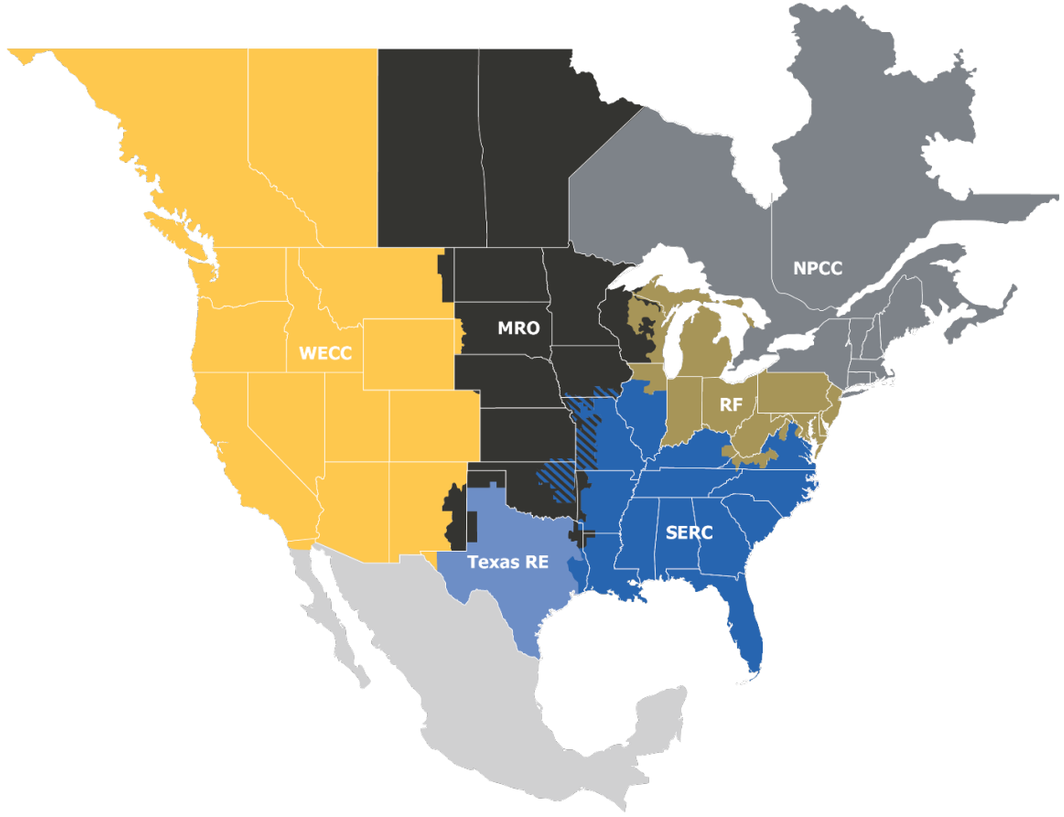
Preface iii
About This Assessment iv
Key Findings 1
Resource Adequacy Assessment and Energy Risk Analysis 2
Other Key Reliability Highlights 4
Recommendations 6
Risk Highlights 7
Summer Temperature and Drought Forecasts 7
Demand and Resource Trends 8
Risk Assessment Discussion 10
Regional Assessments Dashboards 15
MISO 16
MRO-Manitoba Hydro 17
MRO-SaskPower 18
MRO-SPP 19
NPCC-Maritimes 20
NPCC-New England 21
NPCC-New York 22
NPCC-Ontario 23
NPCC-Québec 24
PJM 25
SERC-Central 26
SERC-East 27
SERC-Florida Peninsula 28
SERC-Southeast 29
Texas RE-ERCOT 30
WECC-Alberta 31
WECC-Basin 32
WECC-British Columbia 33
WECC-California 34
WECC-Mexico 35
WECC-Northwest 36
WECC-Rocky Mountain 37
WECC-Southwest 38
Data Concepts and Assumptions 39
Resource Adequacy 42
Changes from Year to Year 43
Net Internal Demand 44
Demand and Resource Tables 45
Variable Energy Resource Contributions 51
Review of 2025 Capacity and Energy Performance 52
Eastern Interconnection–Canada and Québec Interconnection 52
Eastern Interconnection–United States 53
Texas Interconnection–ERCOT 53
Western Interconnection 53

Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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's *2026 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2026.

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

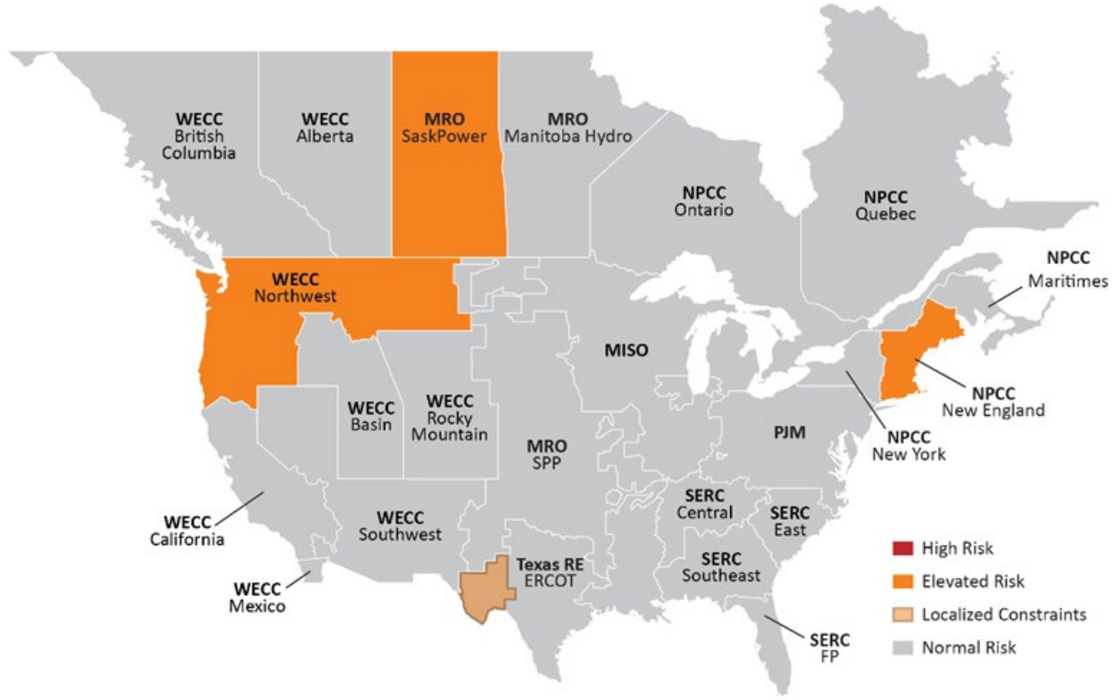
Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or are subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalaches substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the *2025 SRA* of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the *2025 SRA*, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,[2] when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the *2025 SRA* and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

[2] WSOR-WA

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**[3] El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see **Figure 2**). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,[4] starting with sub-average snowpack[5] heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The **Review of 2025 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2025 SRA* and summarizes 2025 resource adequacy events.

- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out 23 assessment areas saw demand increases from the *2025 SRA* projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.[6] The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes 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 issued a Level 3 essential actions alert related to large loads[7] as well as a reliability guideline regarding risk mitigation for emerging large loads.[8]

- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.[9] Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

[3] Climate Prediction Center: ENSO Diagnostic Discussion
[4] Climate Prediction Center: Seasonal Drought Outlook
[5] WSOR-WA
[6] *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, NERC, January 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf
[7] NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control
[8] Risk Mitigation for Emerging Large Loads
[9] NERC State of Reliability reports

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.[10] The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.[11] Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.
- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.[12]

[10] Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information (NCEI)
[11] Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network
[12] *Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps*, https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) in the elevated-risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of above-normal demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[13]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
  - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
  - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
  - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.[14]

[13] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

[14] See Incident Review section of NERC Event Analysis page.

Risk Highlights

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

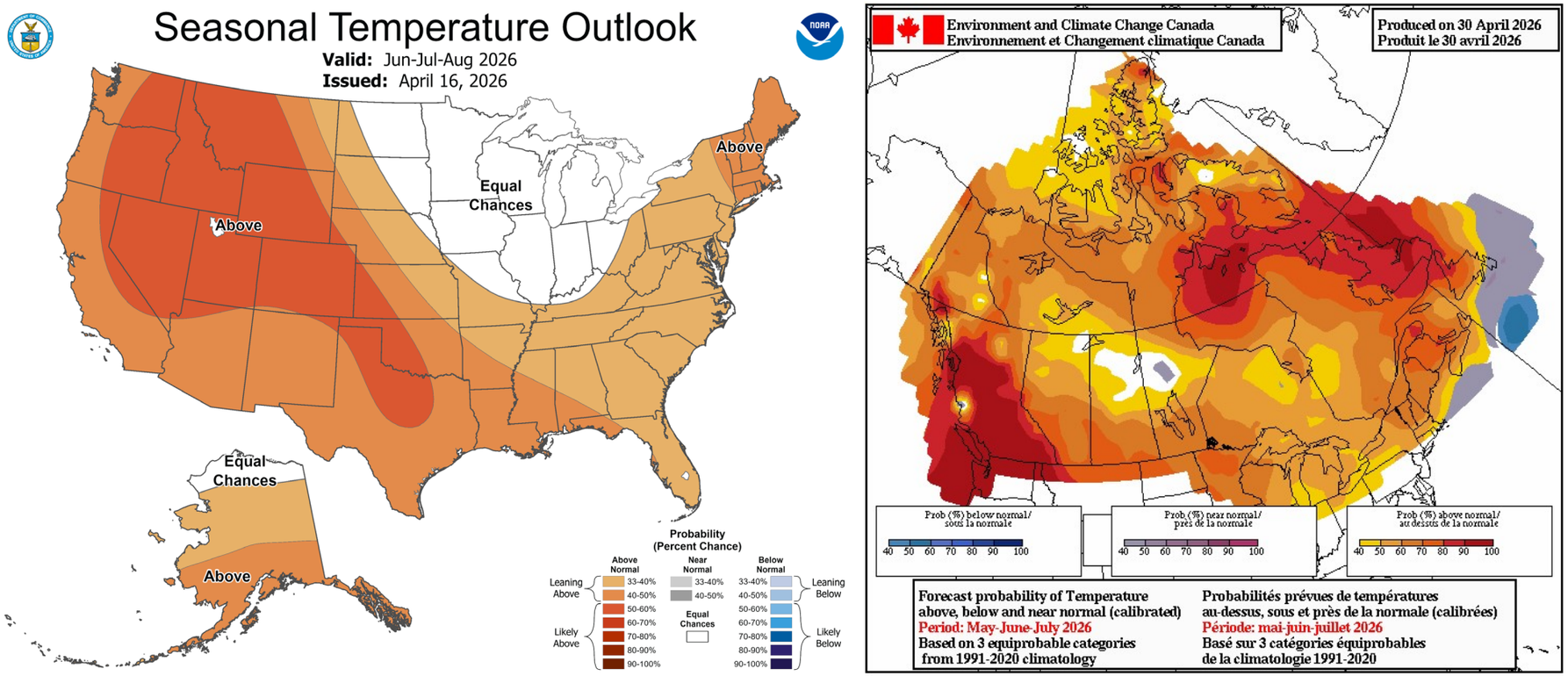


Figure 2: United States and Canada Summer Temperature Outlook[15]

[15] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see **Figure 3**). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

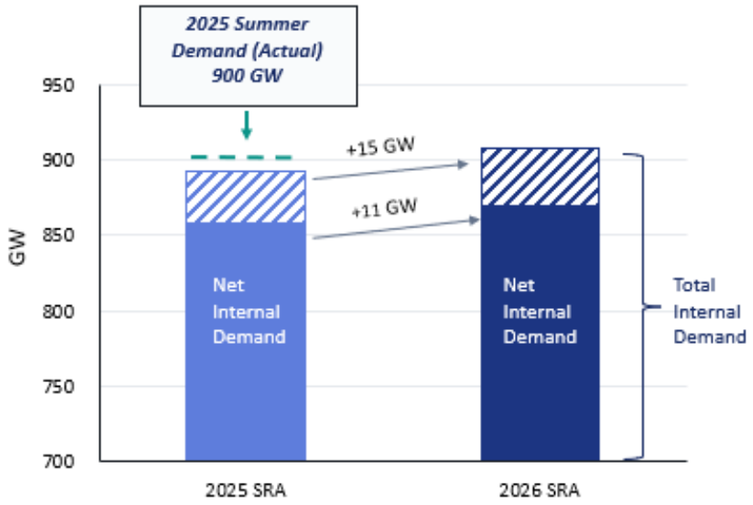


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the **Net Internal Demand** section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see **Figure 4**). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

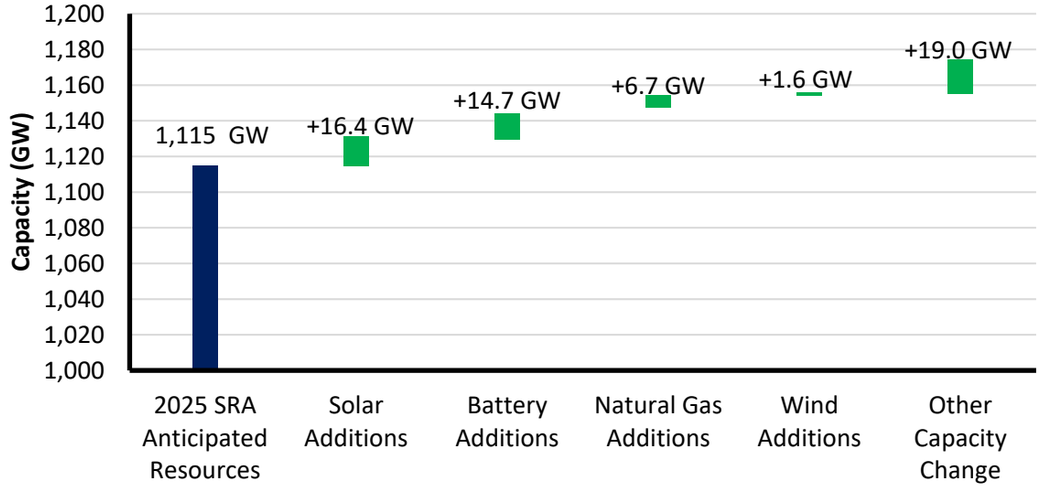


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see **Table 1**). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 2**.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2 hours or higher across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **normal resource scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with **normal resource scenarios**[2] (i.e., typical or expected outage and derate scenarios for conditions) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **reduced resource scenarios**[3] (i.e., extreme outage and derate scenarios)
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible (e.g., LOLH below 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1] The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the peak demand.
[3] **Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4] Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 3**.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each

dashboard provide potential summer peak demand and resource condition information, as well as risk hour resource condition information for areas where the risk hour differs from the peak demand hour. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be on maintenance or forced outage during peak demand conditions. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's summer risk scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 4**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2026. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

EEA Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 MWH/year for the Reference Margin Level. Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results[16] of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

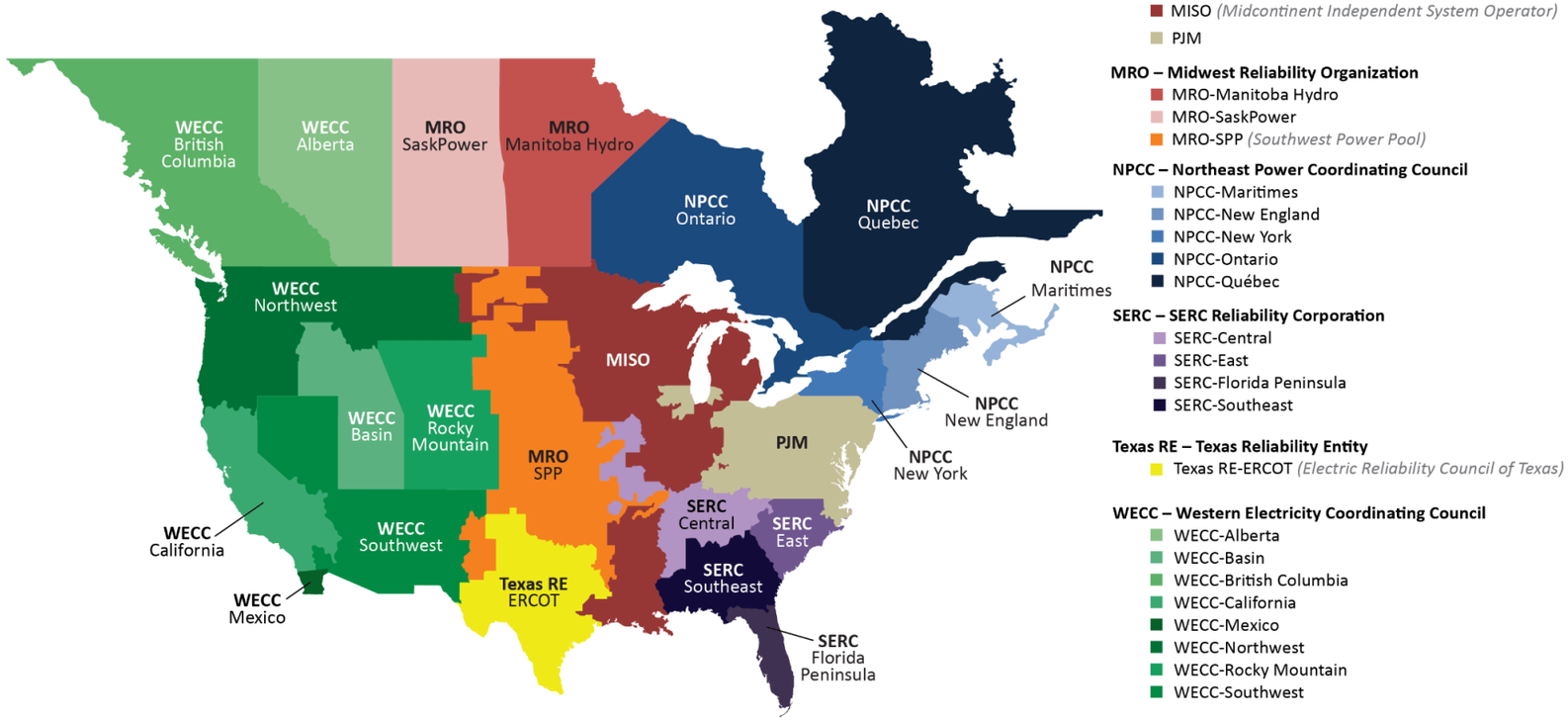
[16] Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. This is categorized by ERCOT as "low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2025 SRA*, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC–Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables** section), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables** section) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

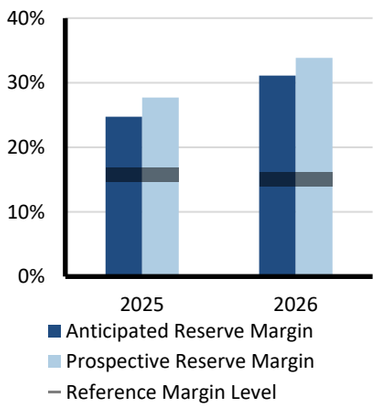
Highlights

- Although MISO's peak load has increased by 2.5 GW from the *2025 SRA*, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

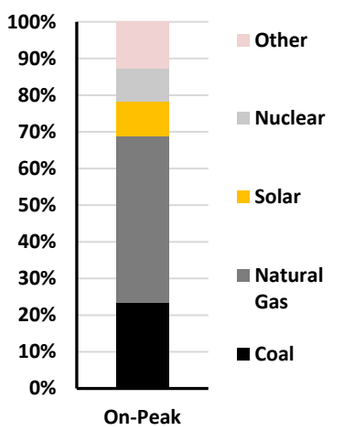
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

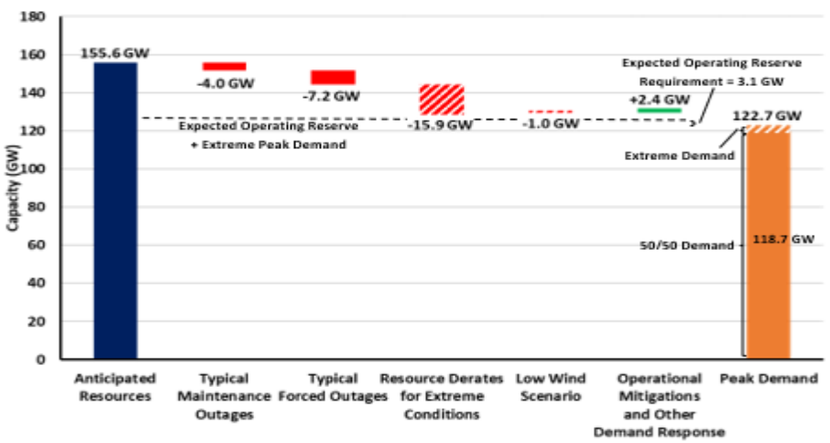
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June–September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme conditions.

MRO-Manitoba Hydro

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 Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

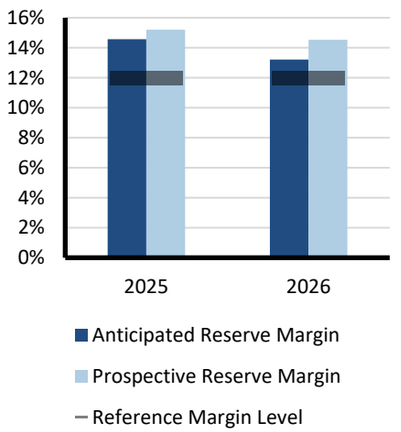
Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

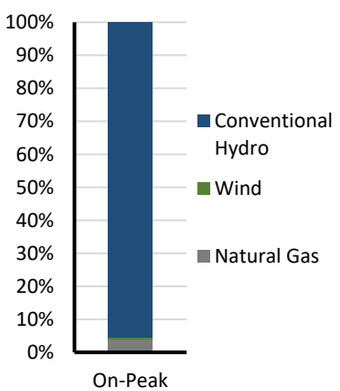
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

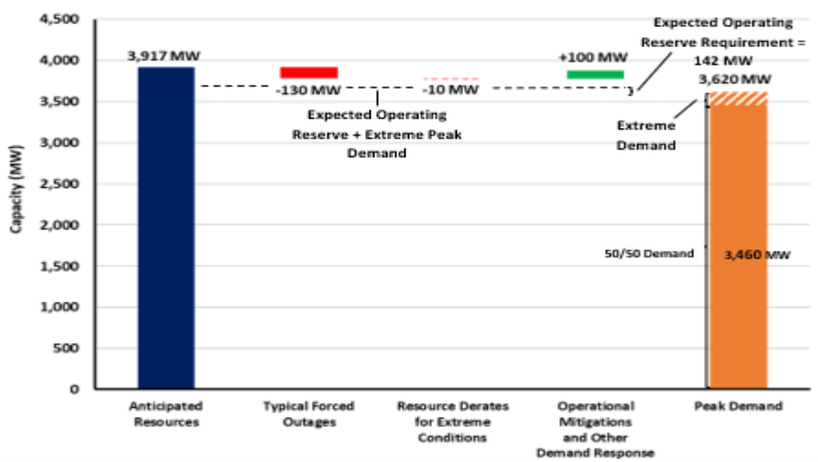
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: 50/50 Demand with allowance for extreme demand based on a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.

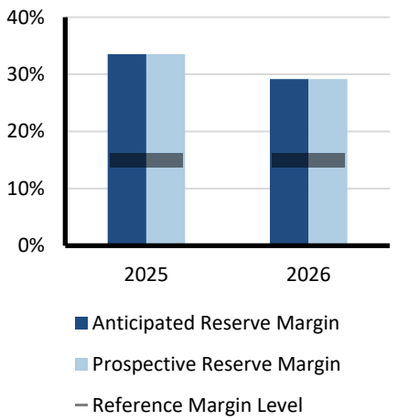
MRO-SaskPower

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 RC 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 BES 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.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the *2025 SRA* projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

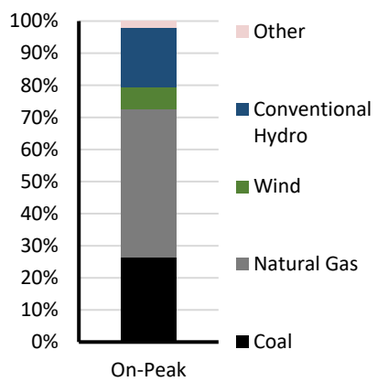
On-Peak Reserve Margin



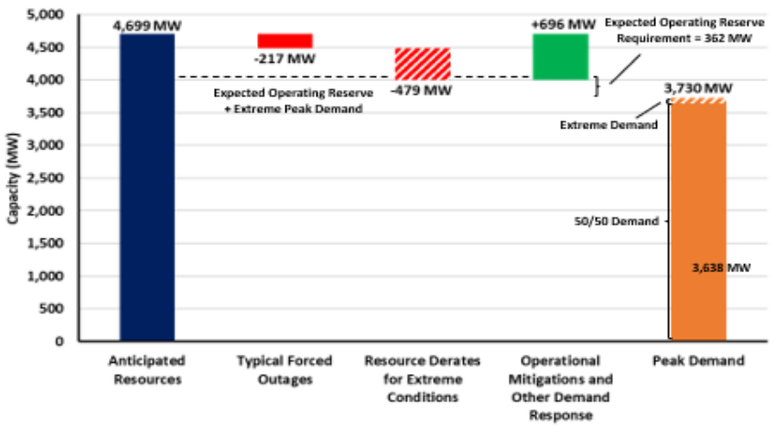
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads.

Forced Outages: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.

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 MRO 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.

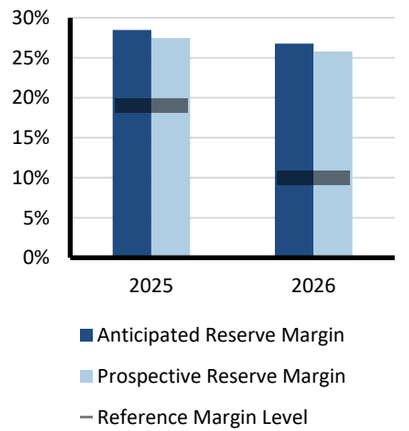
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

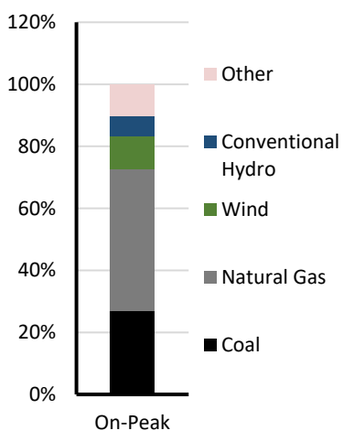
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

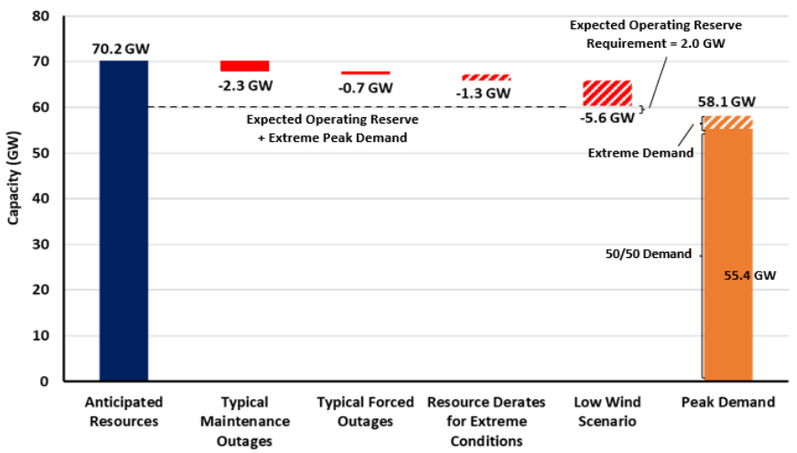
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 4.9% increase from net internal demand.

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process.

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods.

Low Wind Scenario: Derates reflecting an average low-wind day in the summer.

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.

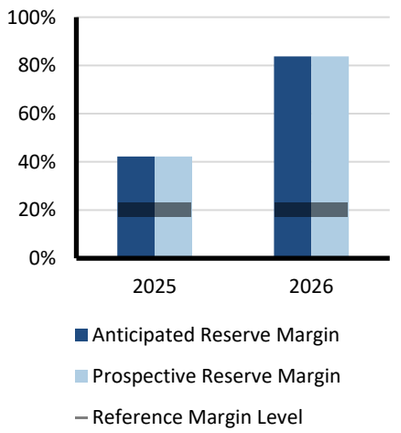
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

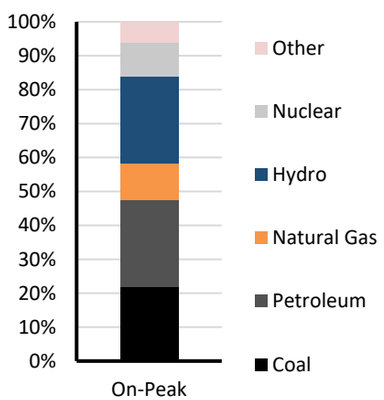
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

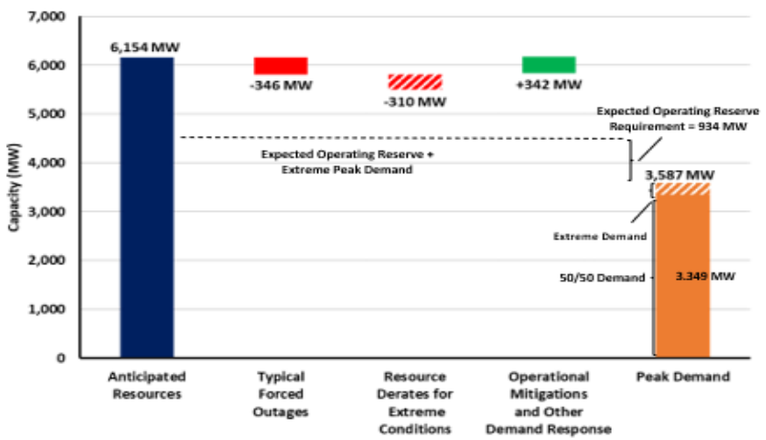
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above 90/10 extreme demand forecast.

Forced Outages: Based on historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.

NPCC-New England

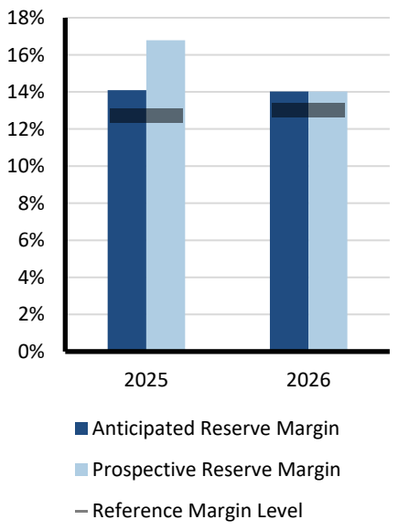
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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.

Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

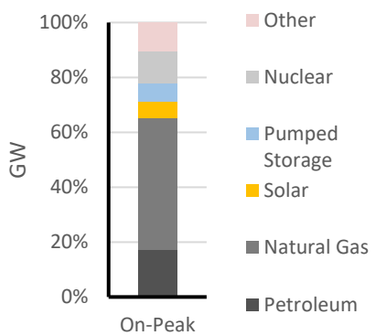
On-Peak Reserve Margin



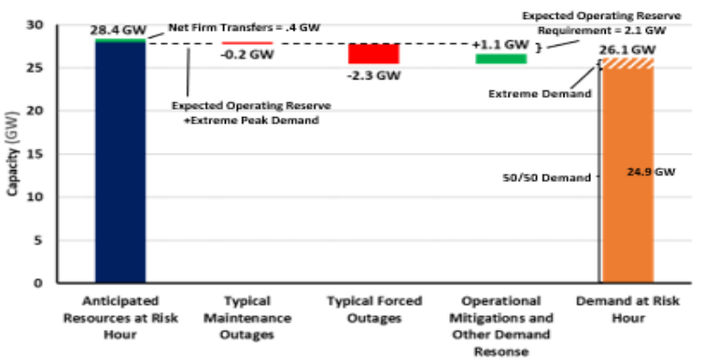
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures.

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 in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, 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. The council approved the 2026–2027 IRM at 24.5%.

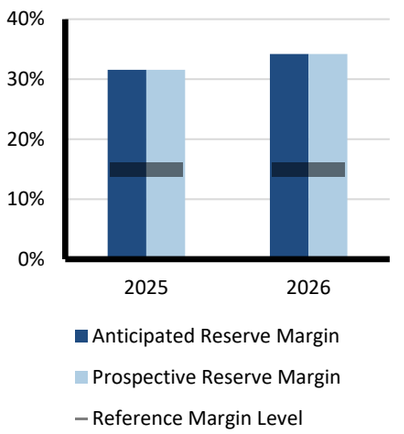
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

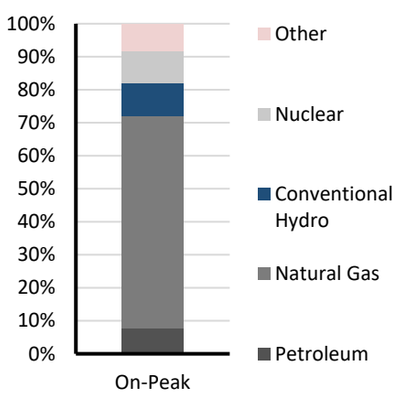
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

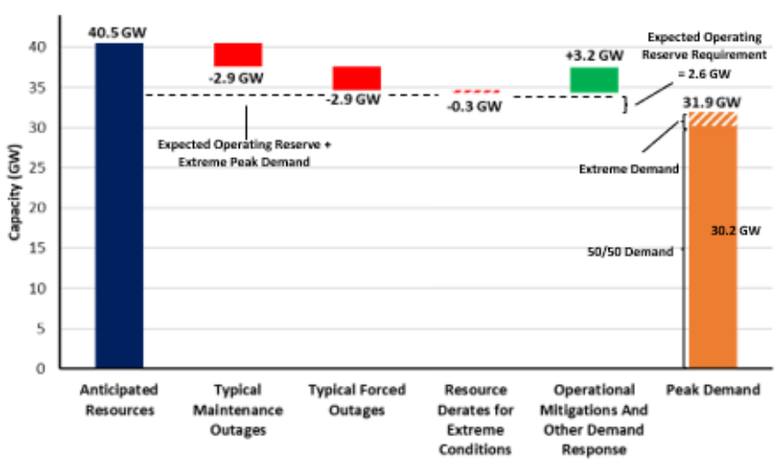
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast. **Maintenance Outages:** Based on historical performance and the new NYISO capacity accreditation process.

Forced Outages: Based on historical five-year averages.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual.

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 BA 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.

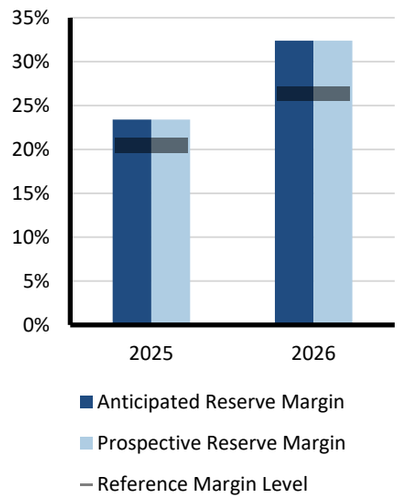
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

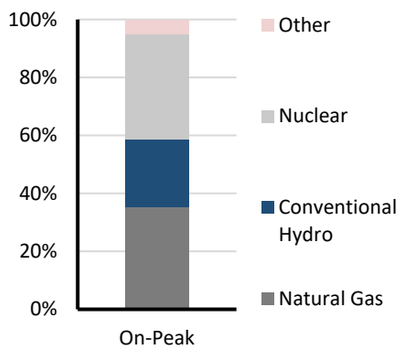
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

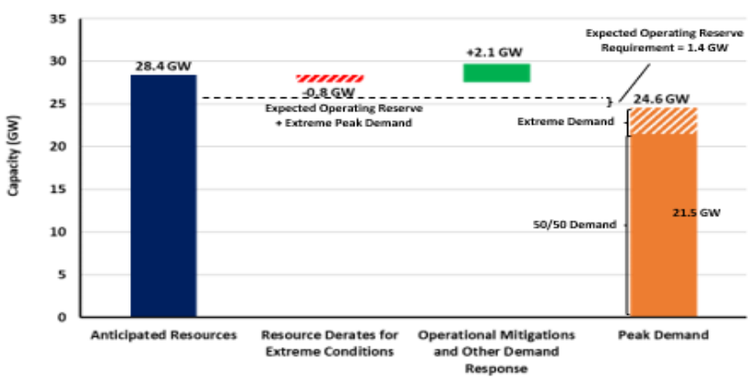
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modeled data.

Extreme Derates: Derived from weather-adjusted temperature ratings of thermal units and adjustments to expected hydro production for low water conditions.

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.

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.

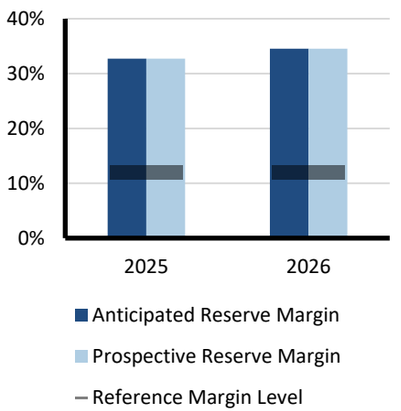
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.

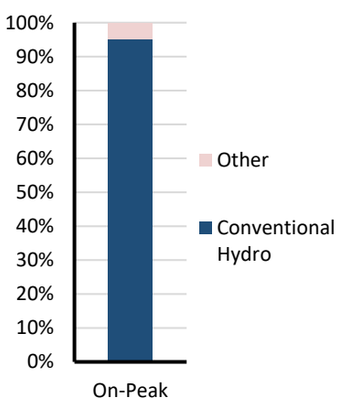
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

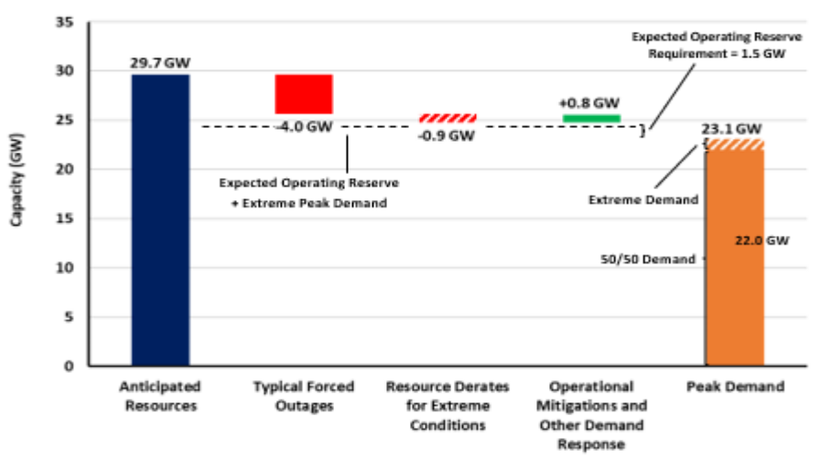
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

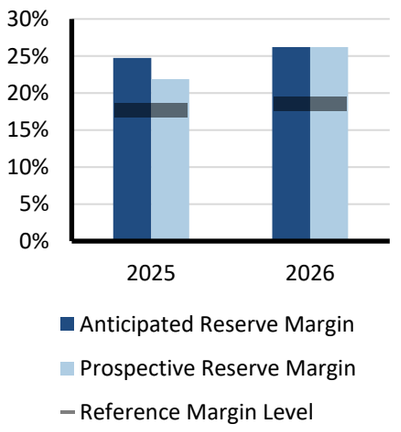
PJM

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 serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

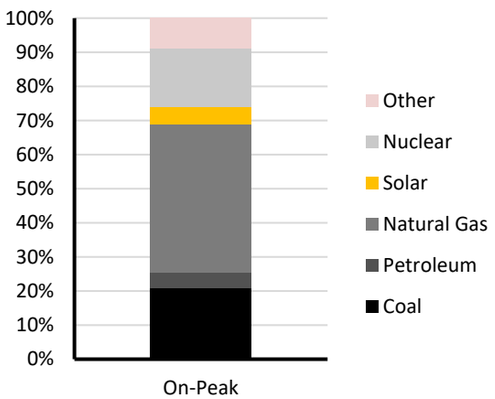
On-Peak Reserve Margin



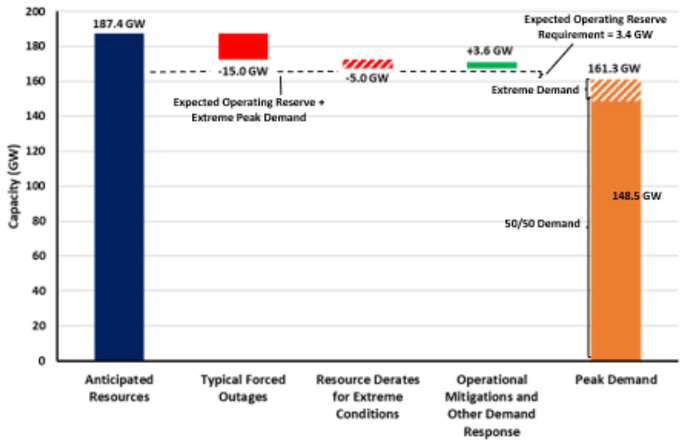
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Accounts for thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.

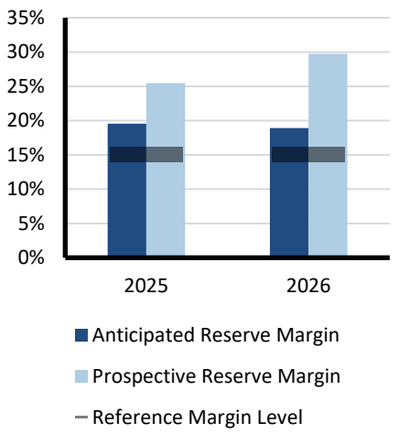
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

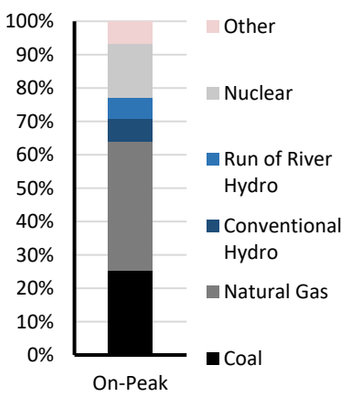
On-Peak Reserve Margin



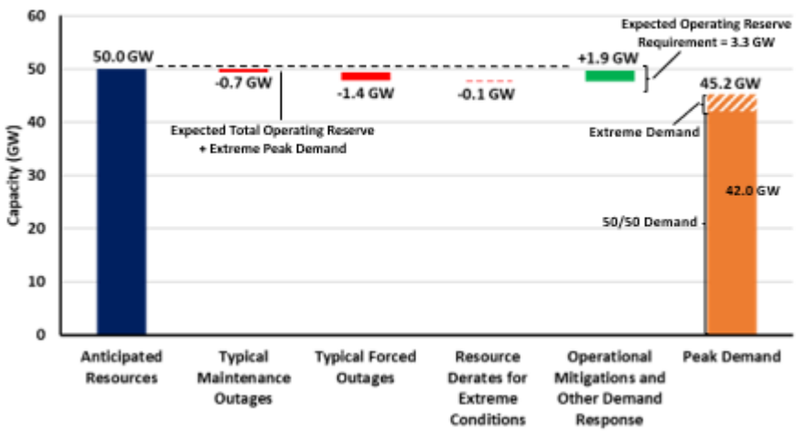
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: 1.9 GW based on operational/emergency procedures.

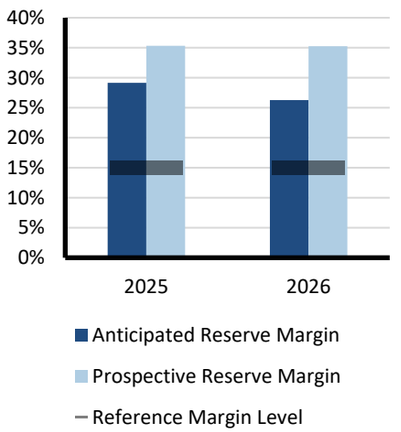
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

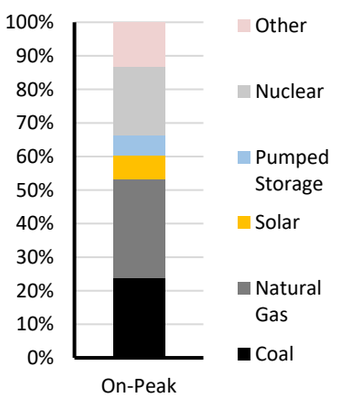
On-Peak Reserve Margin



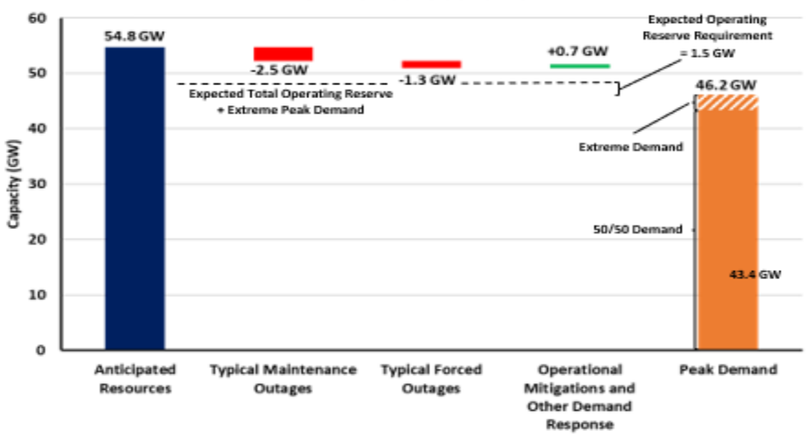
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 728 MW based on operational/emergency procedures.

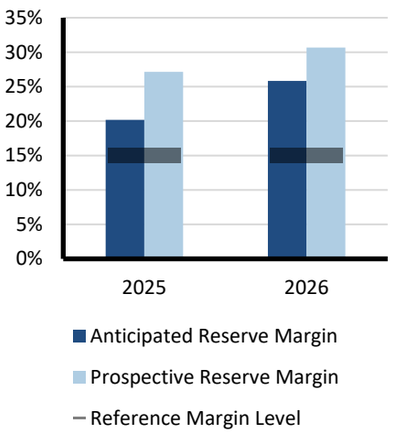
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

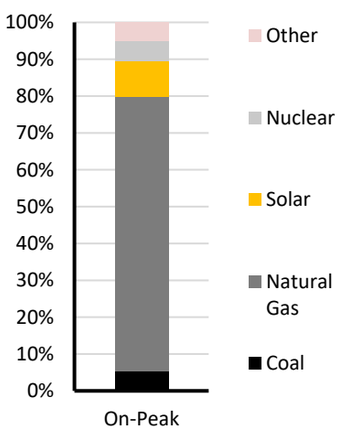
On-Peak Reserve Margin



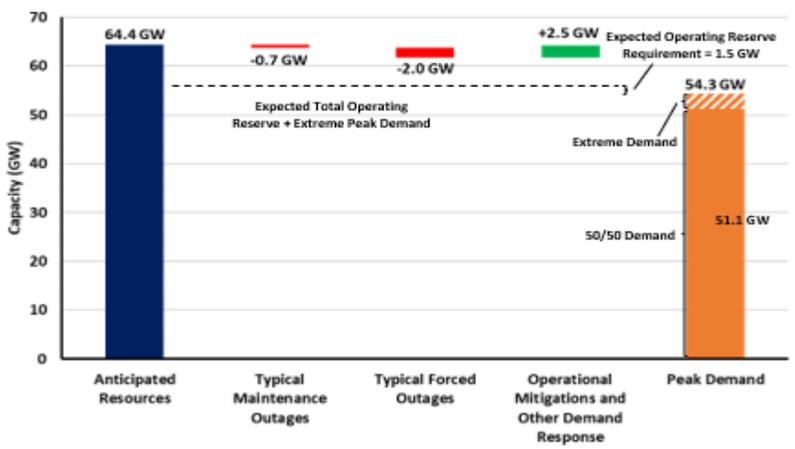
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures.

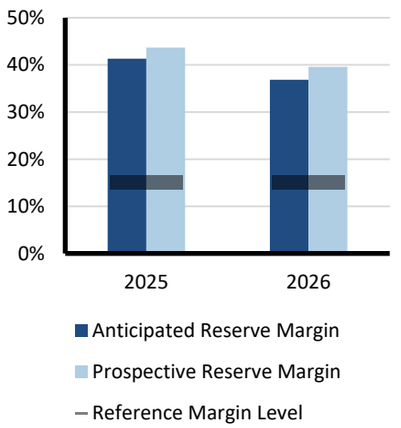
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

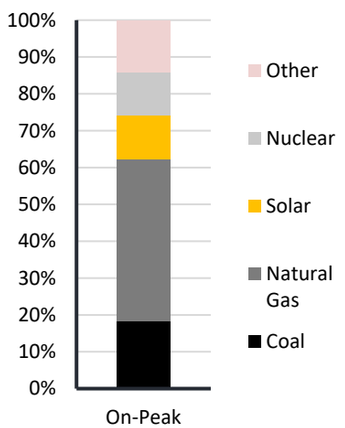
On-Peak Reserve Margin



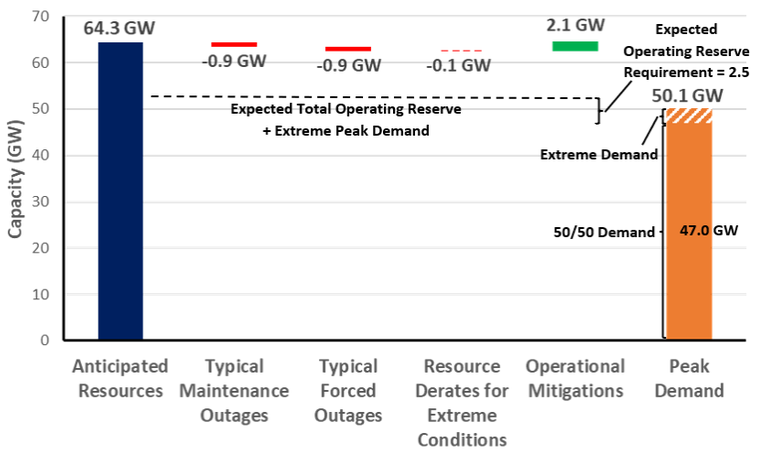
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 2.1 GW based on operational/emergency procedures.

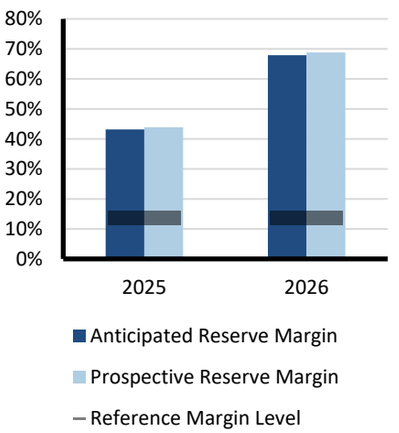
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (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 Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,460 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

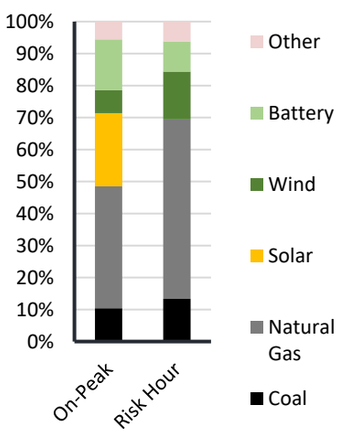
On-Peak Reserve Margin



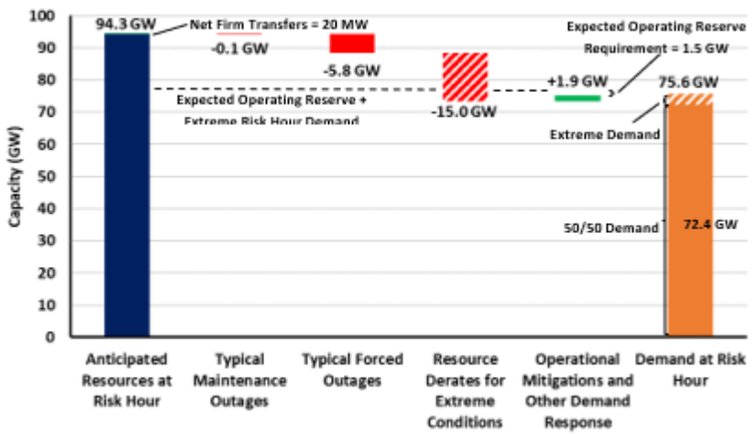
Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.

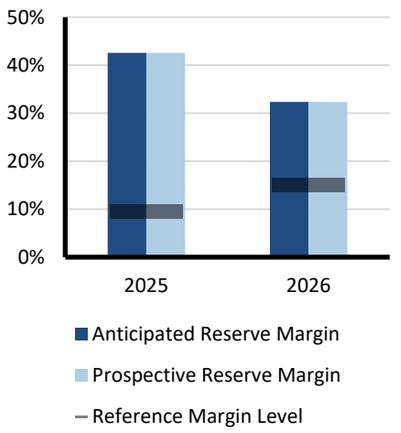
WECC-Alberta

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 RC 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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

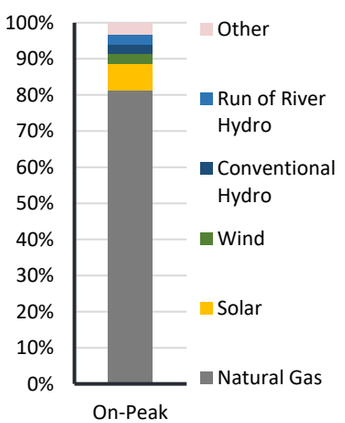
On-Peak Reserve Margin



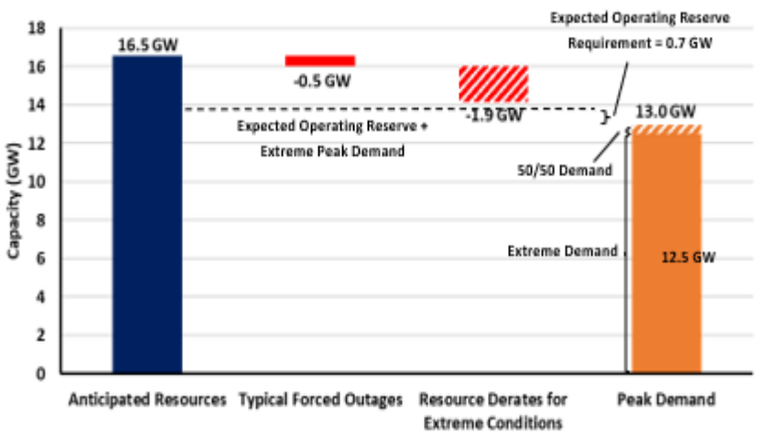
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.

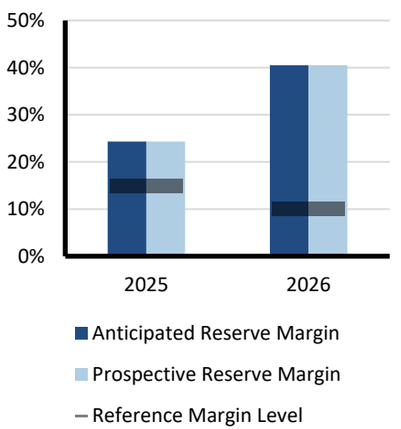
WECC-Basin

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 Balancing Authority 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.

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%

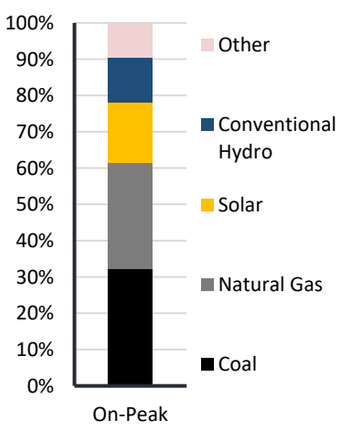
On-Peak Reserve Margin



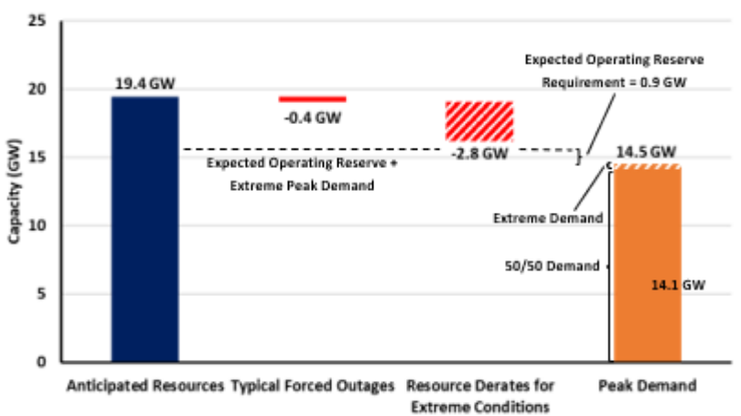
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.

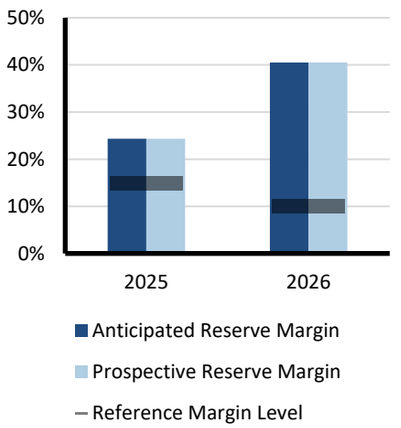
WECC-British Columbia

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 RC 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 BES and its interconnections. BC Hydro operates an integrated system supported by 32 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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

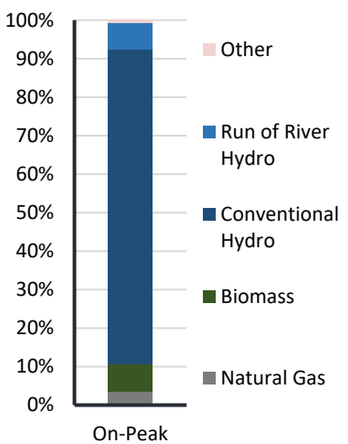
On-Peak Reserve Margin



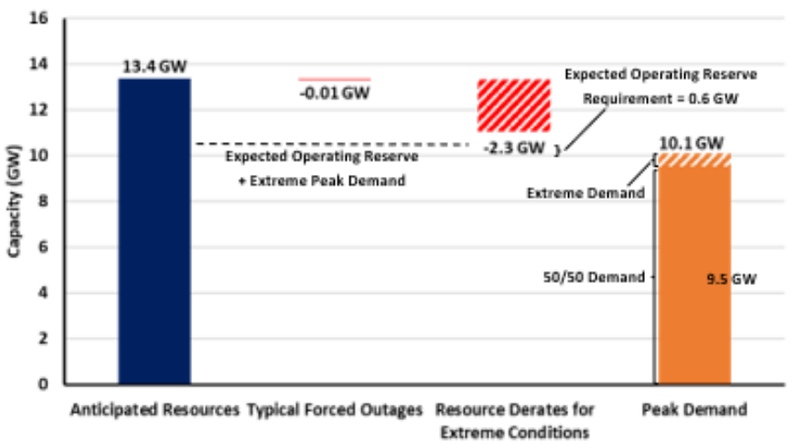
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.

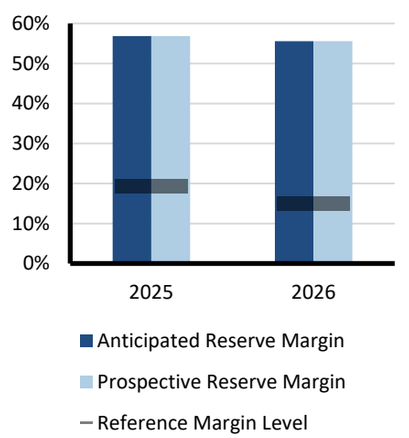
WECC-California

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, the Los Angeles Department of Water and Power, the 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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

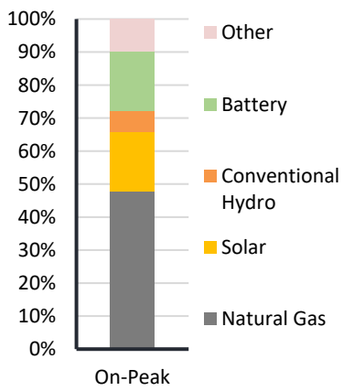
On-Peak Reserve Margin



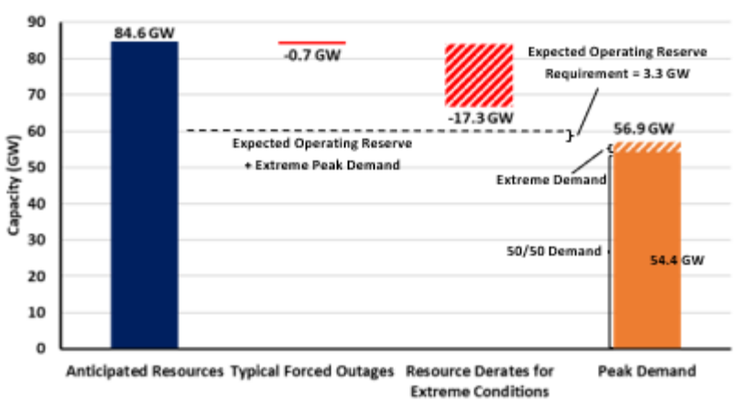
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERVM and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.

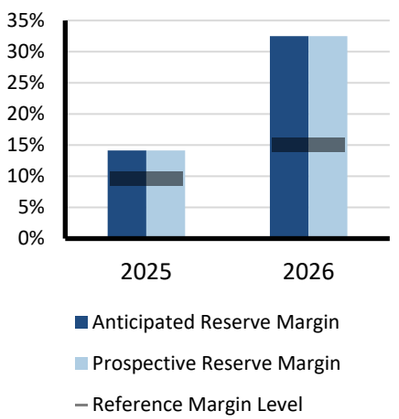
WECC-Mexico

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 Centro Nacional de Control de Energía (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.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the *2025 SRA*.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

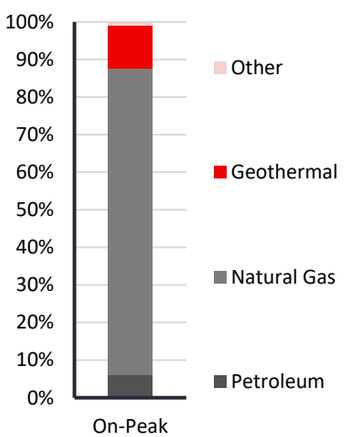
On-Peak Reserve Margin



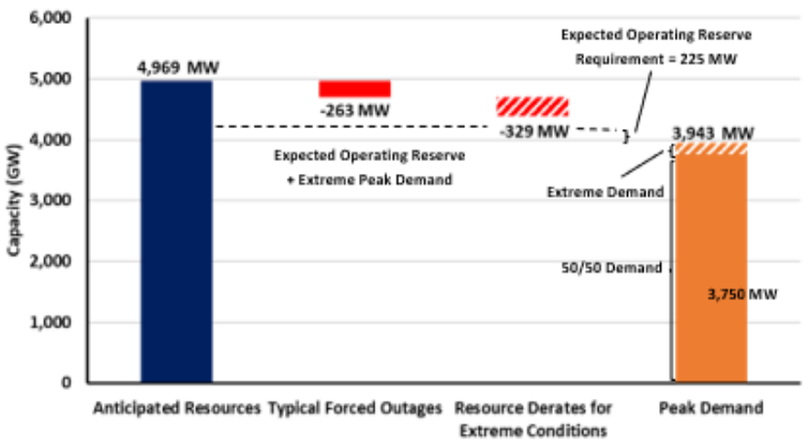
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) resource performance distribution at peak hour.

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.

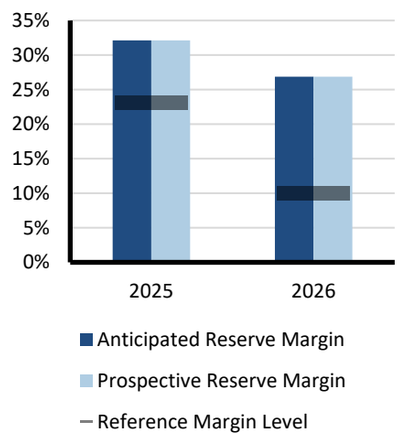
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

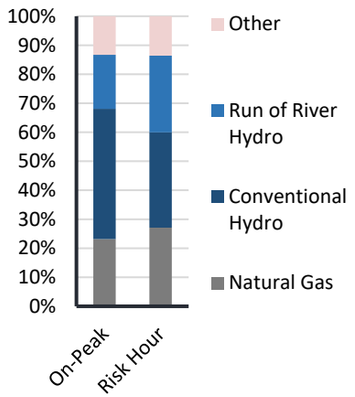
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

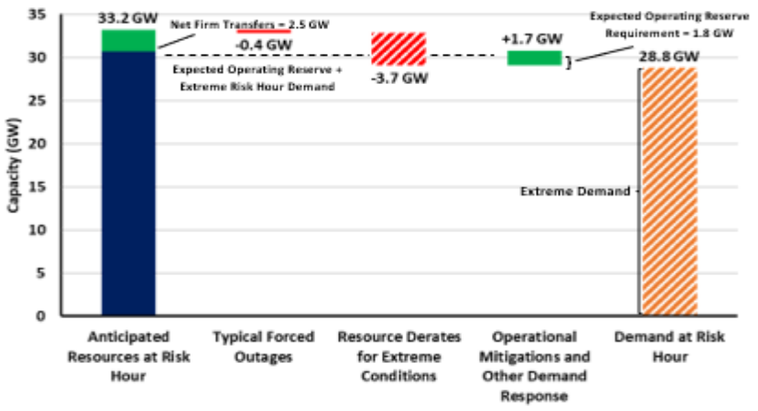
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.

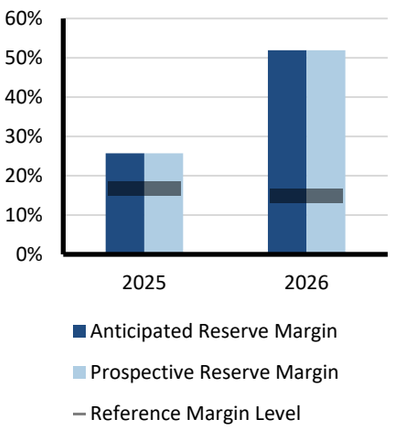
WECC-Rocky Mountain

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

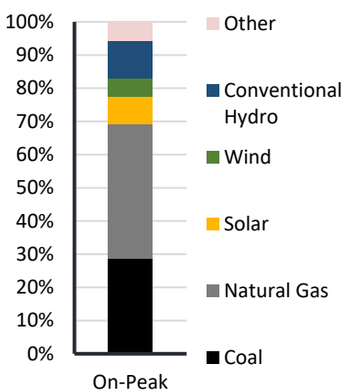
On-Peak Reserve Margin



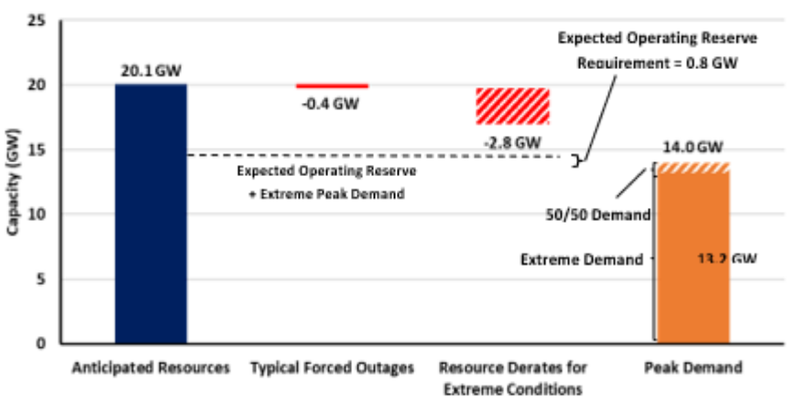
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.

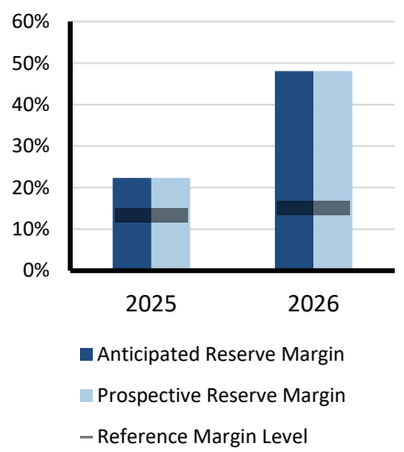
WECC-Southwest

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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

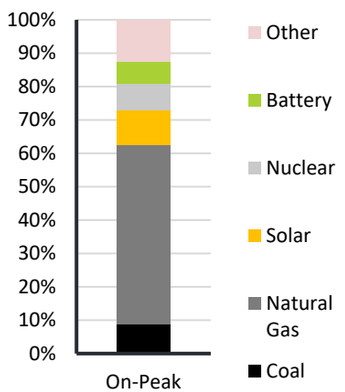
On-Peak Reserve Margin



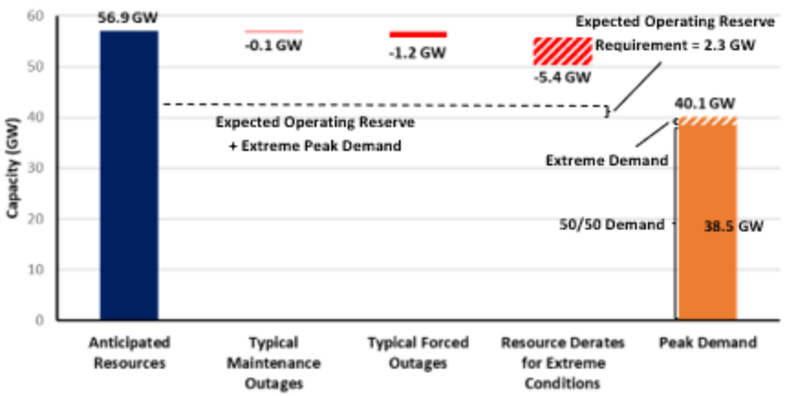
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local).

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) scenario.

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[17] or total internal demand for the summer and winter of each year.[18]
• Total internal demand projections are based on normal weather (50/50 distribution)[19] and are provided on a coincident[20] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

[17] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[18] The summer season represents June–September and the winter season represents December–February.

[19] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[20] 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. SERC calculates total internal demand on a noncoincidental basis.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric 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. Establishing a Reference Margin Level 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 increase demand beyond what was projected in the 50/50 load forecast. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Level s may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[21] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in **Figure 5**.

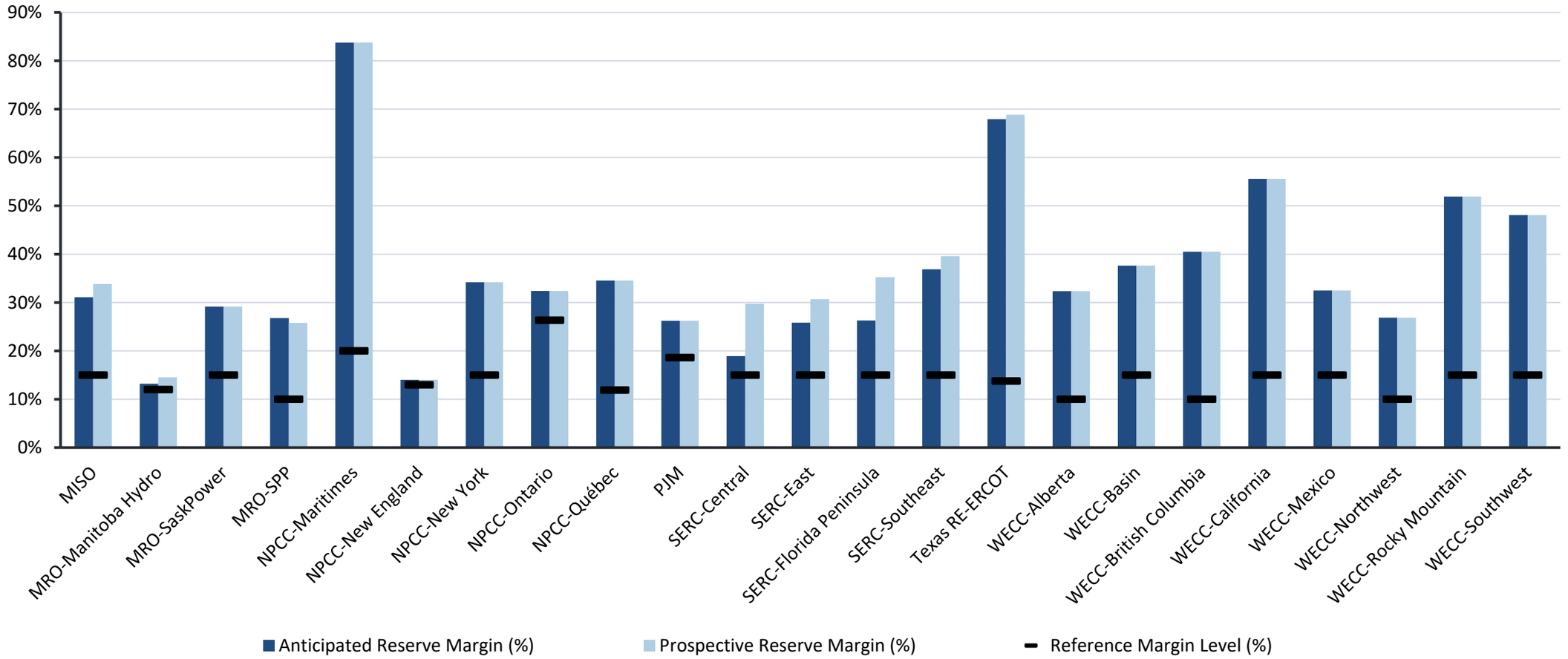


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[21] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

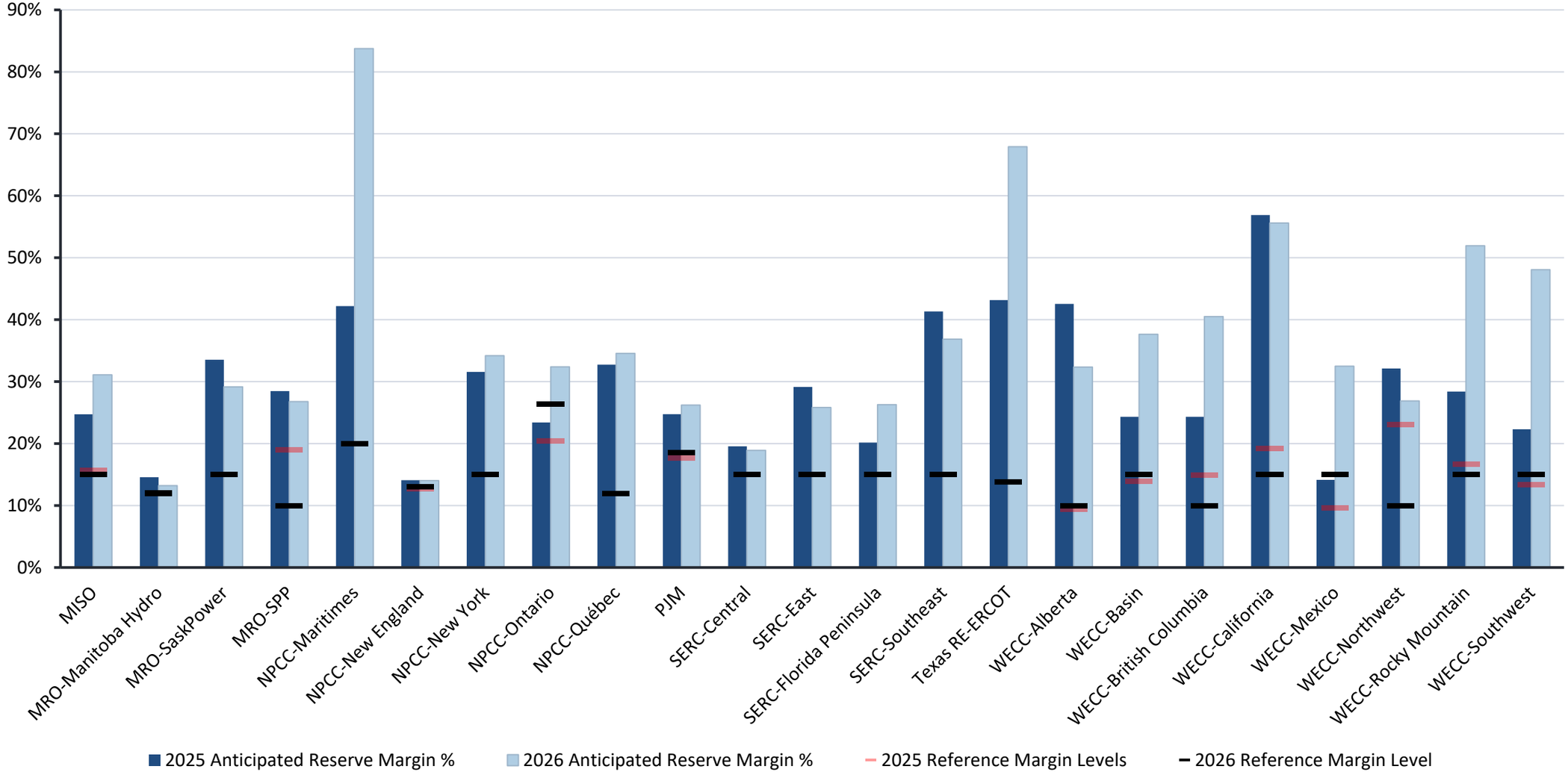


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 7**.[22] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

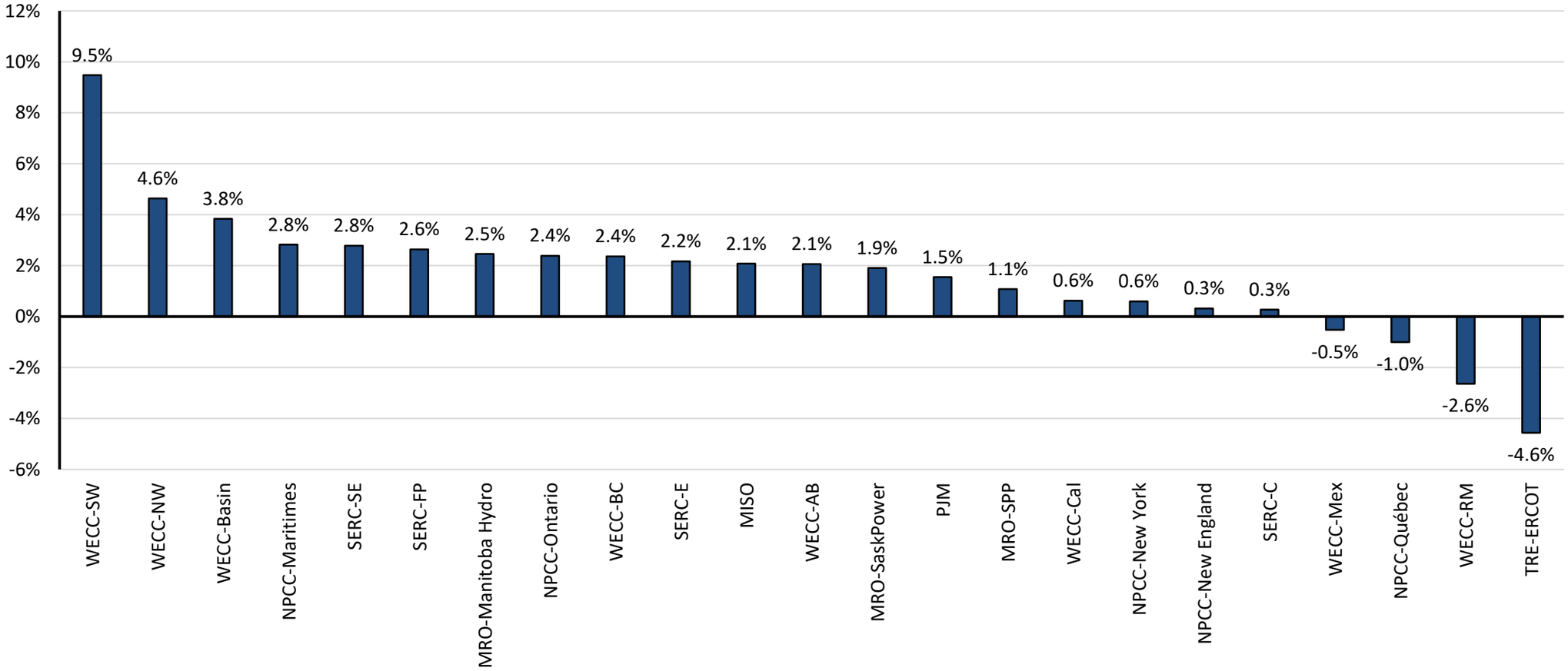


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[22] The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution (MW) of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of-River Hydro	Expected Run-of-River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION[23]	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	**181,153**	**36,673**	**20%**	**168,736**	**101,946**	**60%**	**38,822**	**26,899**	**69%**	**52,442**	**47,005**	**90%**

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

[23] Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States[24] during the meteorological summer period (June–August) and the 11th warmest summer in Canada.[25] Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], topping the prior year's summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh[29]. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave[30] in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record[31] (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,[32] culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,[33] down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.[34] The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.[35]

[24] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)
[25] Climate Trends and Variations Bulletin - summer 2025 - Canada.ca
[26] U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration
[27] Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca
[28] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[29] Electric power generation, monthly generation by type of electricity
[30] Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information (NCEI)
[31] Canada's top 10 weather stories of 2025 - Canada.ca
[32] 2025 Year in Review
[33] Electric power generation, monthly generation by type of electricity
[34] Hydro-Québec - Quarterly Bulletin - Third Quarter 2025
[35] SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the *2024 SRA*, a significant step up from the prior year's summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,[36] though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,[37] resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak[38] of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1[39] on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable[40] during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.[41] Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year's summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

[36] Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire
[37] NYISO Summer 2025
[38] 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines
[39] Microsoft PowerPoint - IMM Quarterly Report, Summer 2025
[40] DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive
[41] 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2[5] 91.3[5]	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-MX	3.5	3.8 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.
[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2025 SRA*.
[4] Values from NERC Generator Availability Data System for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.
**Data unavailable - Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.