EXHIBIT 61

Short-Term Energy Outlook Data Browser

Release Date: December 9, 2025 | **Next Release Date:** January 13, 2026

Standard Tables

1. U.S. Energy Markets Summary

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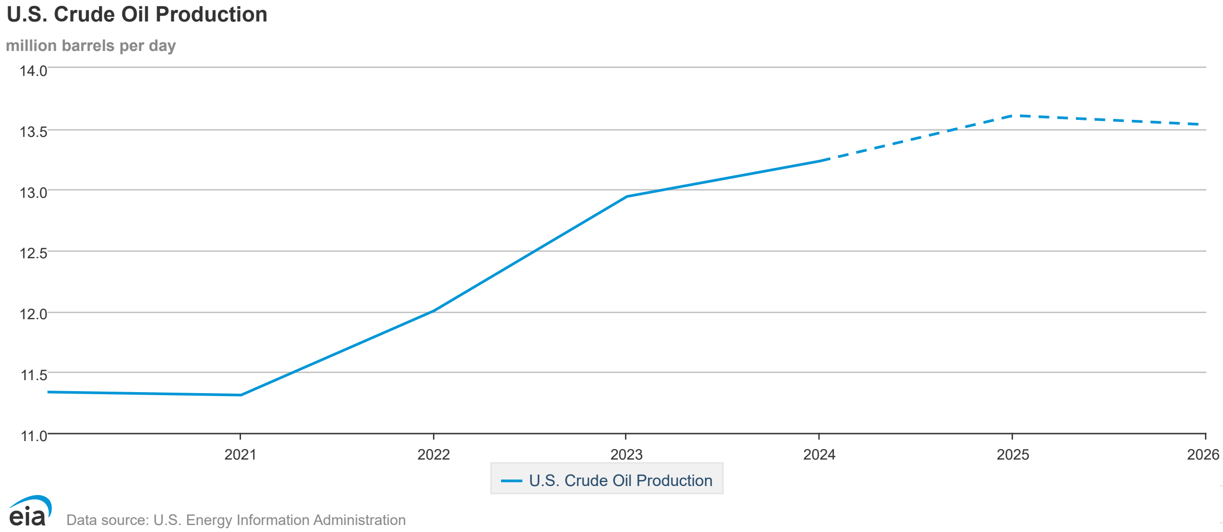

2020 2026 Annual Quarterly Monthly HELP DOWNLOAD

	2025	2026		
Liquid Fuels (million barrels per day)	).28	20.46	20.59	20.58
Natural Gas (billion cubic feet per day)	).37	90.43	91.84	90.82
Coal (million short tons)	426	411	448	426
Electricity (billion kilowatthours per day)	).99	11.23	11.50	11.69
Renewables (quadrillion btu)	3.29	8.70	8.78	9.43
Total Energy Consumption (quadrillion btu)	3.73	94.54	95.85	95.68
Energy Prices				
Crude Oil West Texas Intermediate Spot (dollars per barrel)	7.58	76.60	65.32	51.42
Natural Gas Henry Hub Spot (dollars per million btu)	2.54	2.19	3.56	4.01
Coal (dollars per million btu)	2.51	2.47	2.42	2.40
Macroeconomic				
Real Gross Domestic Product (billion chained 2012 dollars -	724	23,358	23,820	24,354
Percent change from prior year (percent change from p	2.9	2.8	2.0	2.2
GDP Implicit Price Deflator (index, 2017=100)	22.4	125.4	128.9	132.7
Percent change from prior year (percent change from p	3.7	2.5	2.7	2.9
Real Disposable Personal Income (billion chained 2017 dolla	218	17,724	18,066	18,641
Percent change from prior year (percent change from p	5.7	2.9	1.9	3.2
Manufacturing Production Index (index, year 2017=100)	)0.0	99.5	100.6	100.9
Percent change from prior year (percent change from p	-0.4	-0.4	1.0	0.3
Weather				
U.S. Heating Degree Days (degree days)	802	3,690	4,042	3,921
U.S. Cooling Degree Days (degree days)	480	1,634	1,537	1,589

NOTICE: Changes to the available data series

EXHIBIT 62

https://www.wsj.com/business/energy-oil/trump-oil-drilling-saudi-arabia-71c095ff

EXCLUSIVE ENERGY & OIL Follow

U.S. Frackers and Saudi Officials Tell Trump They Won't Drill More

President says lower prices will solve many of the country's problems but finds early resistance in the oil market

By *Collin Eaton* Follow , *Benoit Faucon* Follow and *Benoît Morenne* Follow

Feb. 3, 2025 5:30 am ET

Pump jacks operating in a field near Hays, Kan. CHARLIE RIEDEL/AP

President Trump wants to boost oil drilling. His allies in the U.S. shale industry and Saudi Arabia are pushing back.

Trump for months has encouraged the U.S. shale industry to "drill, baby drill," but another American oil boom isn't in the cards soon, no matter how many regulations are rolled back, according to oil executives. After many producers overdrilled themselves into bankruptcy during the shale boom's heyday, the industry is now focused on keeping costs down and returning cash to investors.

The president's advisers concede that U.S. frackers won't pump much more, according to people familiar with the matter. The advisers say his best lever to bring down prices might be to persuade the Organization of the Petroleum Exporting

Countries and Saudi Arabia, the group's de facto leader, to add more barrels to the market.

But Saudi Arabia has told former U.S. officials that it also is unwilling to augment global oil supplies, say people familiar with the matter. Some of those former officials have shared the message with Trump's team.

The president believes a fresh tidal wave of oil would solve many of his problems: It could quell inflation and pave the way for interest-rate cuts. It could also strengthen his hand in coming confrontations with petrostates Russia and Iran.

In a January speech, Trump said he planned to ask Saudi Arabia and other OPEC members to bring down oil prices. The president is planning to visit the kingdom in one of his first foreign trips of his second term, and he is expected to push for higher Saudi oil production in person.

Trump's fixation on oil prices is vexing to some in the industry. Currently around $73 a barrel, prices are relatively low compared with 2022, when they averaged over $94 a barrel and the national average gasoline price hit a record over $5 a gallon. Gasoline prices are averaging $3.10. The president has declared a national "energy emergency" and vowed to cut Americans' overall energy costs in half.

Keith Kellogg, Trump's special envoy to Ukraine and Russia, has said global producers should try slashing oil prices to $45 a barrel, to pressure Russia into ending the war with Ukraine.

Keith Kellogg, the president's special envoy to Ukraine and Russia SIAVOSH HOSSEINI/ZUMA PRESS

Such prices could be disastrous for U.S. frackers and Saudi Arabia—Trump's two most powerful friends in the global oil market. The last time prices sank below $45, during the pandemic in 2020, it prompted a painful war for market share between Saudi Arabia and Russia and pushed dozens of shale drillers into bankruptcy.

At lower oil prices, Saudi Arabia would struggle to generate enough revenue to pay for social services, monthly payments to citizens and big infrastructure projects. It will need about $90 a barrel this year to balance its budget, according to the International Monetary Fund.

There is a clash coming between Trump and Saudi Arabia over oil prices, one of the former U.S. officials said.

Trump's advisers have told some oil-and-gas donors they understand the president can't rely on U.S. frackers to boost production in the short term, people familiar with the discussions said.

"Companies are no longer pursuing growth at all costs," said Kaes Van't Hof, president of West Texas oil producer Diamondback Energy. "Shale is in a much different phase of its life cycle."

Longer term, the advisers say Trump's support of U.S. oil and gas—including by scrapping environmental regulations—will make the sector more appealing to investors. That, in turn, would lead to more capital flowing into the industry and eventually increase output. Making it easier to build pipelines and other infrastructure could also increase fossil-fuel demand, potentially spurring drilling, the advisers say.

Aspirations to marginally boost U.S. output over time aren't completely unrealistic, said Ed Crooks, vice chairman, Americas, at energy consulting firm Wood Mackenzie. It depends on whether the administration is able to improve the economics of production, but it could take years and would pale in comparison to shale's boom years.

Among Trump's early regulatory changes, "we don't see anything that will make a colossal difference to the economics of production," Crooks said.

Oil executives said they expect U.S. production, which is already at record levels, to grow modestly this year, unless prices surge. The Energy Department projects domestic output will rise about 2% to about 13.7 million barrels a day by December, and then stay relatively flat in 2026.

That level of production would do little to sate Trump's immediate appetite for a gusher of oil. It might also hamper his ability to slap oil and gas sanctions on Russia or Iran, measures that would likely lead to fewer barrels on the market and an increase in oil prices, undermining Trump's promise to voters.

Before the inauguration, Trump's transition team told people that he intended to go to Saudi Arabia to secure assurances they would step in to fill the gap if he ramps up pressure on Iran. Trump's team has estimated Iran's exports could be reduced by

500,000 to 750,000 barrels a day from sanctions under consideration, according to people familiar with the matter.

Storage tanks, as seen several years ago, at an Aramco oil facility in Saudi Arabia. AMR NABIL/AP

The sanctions discussed if Iran doesn't curb its nuclear program include targeting Chinese ports that import Iran's oil, Iraqi oil deals with Iran and other places used to facilitate the transfer of Iranian oil.

Two former U.S. officials were told the kingdom would be reluctant to rush to boost production because they were weary of a repeat of the 2019 oversupply.

That year, the Trump administration asked the kingdom to anticipate the return of the Iran embargo by opening up the spigots. But Trump surprised the Saudis by allowing exemptions for some Iranian oil buyers in Asia—leading to an oil glut and lower prices.

Another factor is that the Saudis say privately they need Russia's involvement in OPEC+—an alliance between the cartel and other producers, including Russia—to prop up prices.

The Saudi government is also giving priority to peaceful relations with Iran, an about-face from their adversarial attitude back in 2018. Back then, the Saudis opposed the nuclear agreement and backed sanctions. Now, the kingdom wants to be part of nuclear negotiations rather than lobbying against them, Saudi officials say.

Write to Collin Eaton at collin.eaton@wsj.com, Benoit Faucon at benoit.faucon@wsj.com and Benoît Morenne at benoit.morenne@wsj.com

Appeared in the February 4, 2025, print edition as 'Trump's Oil Allies Resist His Push to Drill'.

Further Reading

OPINION **A Big Oil Case at the Supreme Court**

U.S. Push Into Venezuela Oil Patch Raises Questions About OPEC Dynamic

Trump Team Works Up Sweeping Plan to Control Venezuelan Oil for Years to Come

Trump's Hint to Oil Executives Weeks Before Maduro Ouster: 'Get Ready'

Citgo Is a Crown Jewel of Venezuela's Oil Industry. Elliott Is Set to Reap the Benefits.

Videos

EXHIBIT 63

Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region 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.

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability,* Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[7]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[5] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks,* PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection,* 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired units 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. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk,* PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id*.

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[21] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[22]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.

[16] *Id*.

[17] *Id.* at 16, Table 1.

[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

[19] *Id*.

[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[21] *Id.* at 14.

[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").

[23] *Id*. at P 10.

[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," 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."[32] 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."[33]

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[25] *PJM Interconnection,* 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent 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."[34] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[35] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

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[34] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[35] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[36] *See* Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[37] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy, at 28 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[41] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] 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).
[44] 16 U.S.C. § 824a(c)(4).

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

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

C. All operation of the Eddystone Units 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. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units 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, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

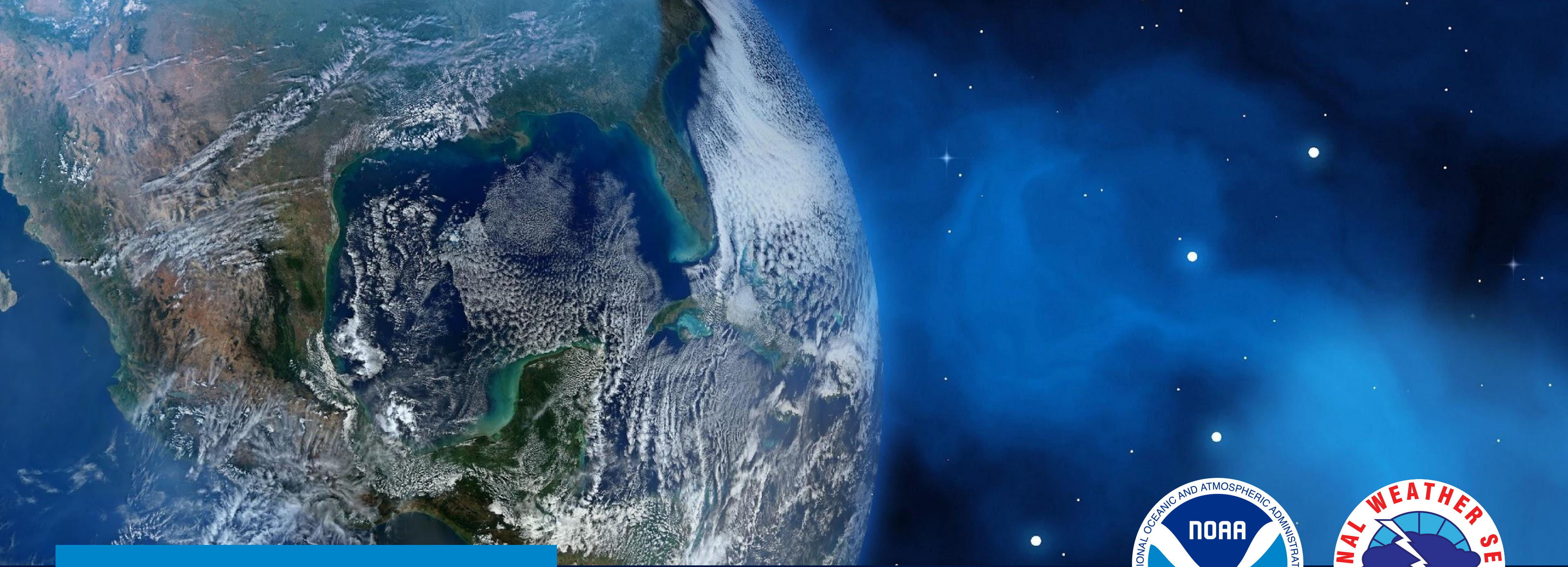
Chris Wright

Chris Wright
Secretary of Energy

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

<u>Pennsylvania Public Utility Commissioners</u>
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

EXHIBIT 64



Winter Outlook 2025-2026

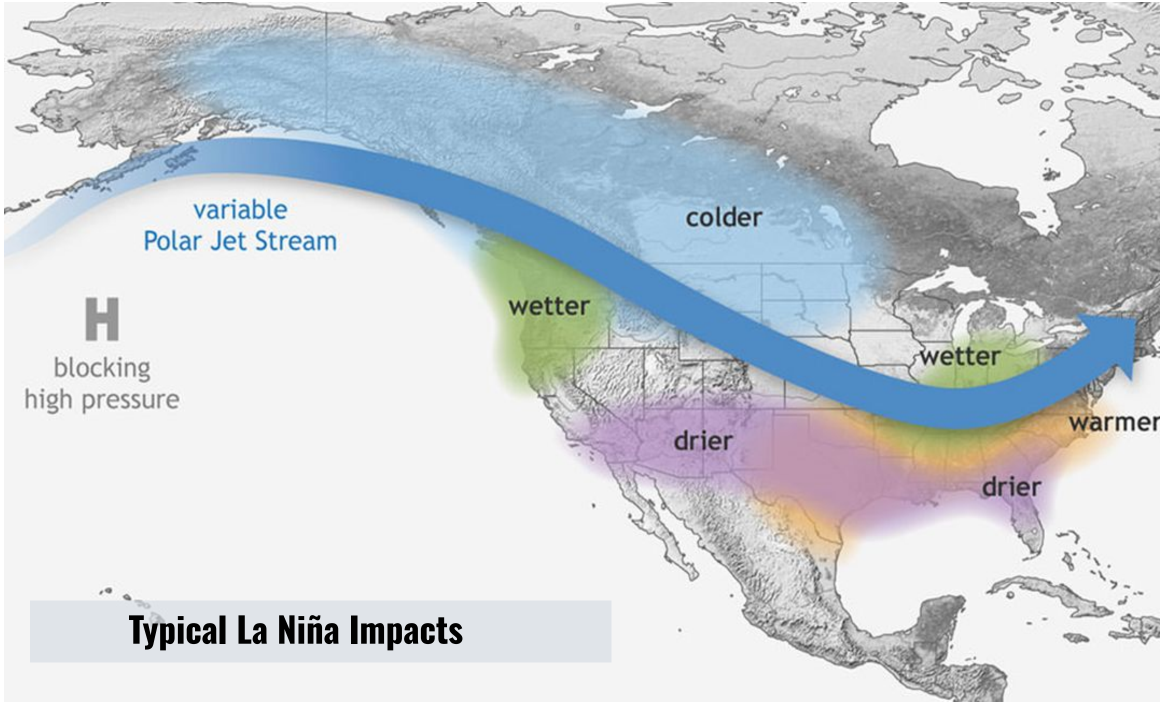
National Weather Service Aberdeen, SD

U.S. Department of Commerce
National Oceanic and Atmospheric Administration
National Weather Service

Seasonal Outlooks Influenced by La Niña

El Niño/La Niña are the warm and cool phases of a recurring climate pattern across the tropical Pacific Ocean that can affect weather worldwide.

- **La Niña:** Conditions are present and favored to persist through December 2025 - February 2026, with a transition to neutral likely in January-March 2026 (55% chance).
- Current guidance suggests **a weak and short duration La Niña**, but still favors cooler and wetter conditions for the Northern Plains
- These are typical impacts, but every winter is unique!



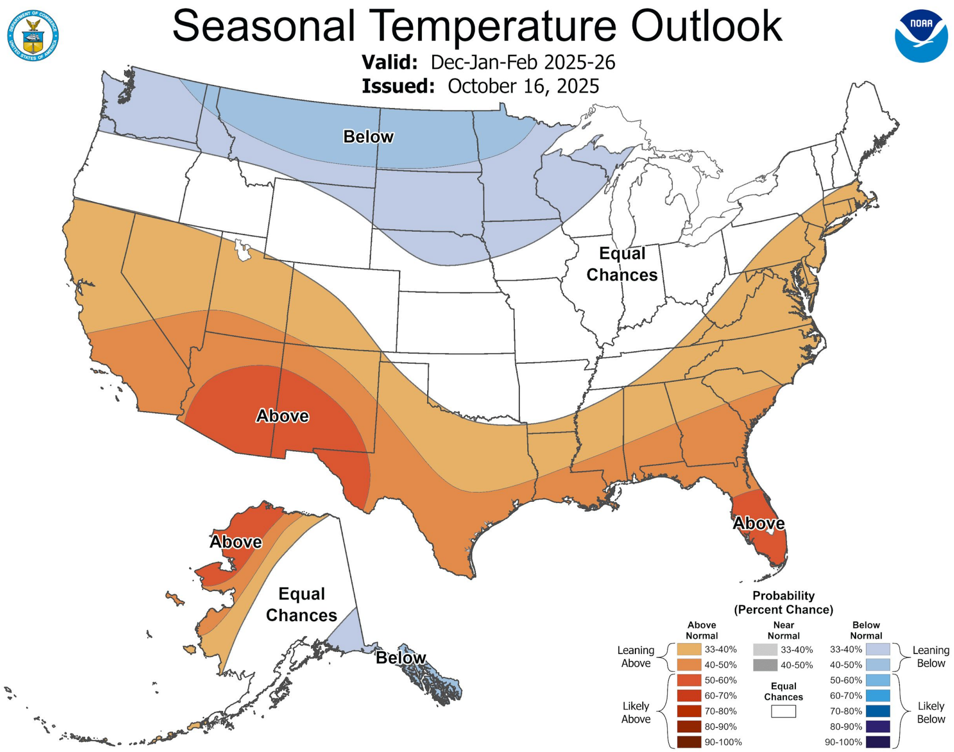
U.S. Seasonal Temperature Outlook

December-January-February

- ➔ Warmer-than-average temperatures are favored from the southern tier of the U.S. to the eastern seaboard and northern Alaska. These probabilities are strongest along the Southwest US and most of Florida.

- ➔ **Below-average temperatures** are slightly favored from the Pacific Northwest to the **Northern Plains** and western Great Lakes region. Below-average temperatures are also slightly favored across southern Alaska. The probabilities are strongest across Montana, North Dakota and northern Minnesota.

- ➔ The remaining areas have equal chances of below-, near-, or above-average seasonal mean temperatures.



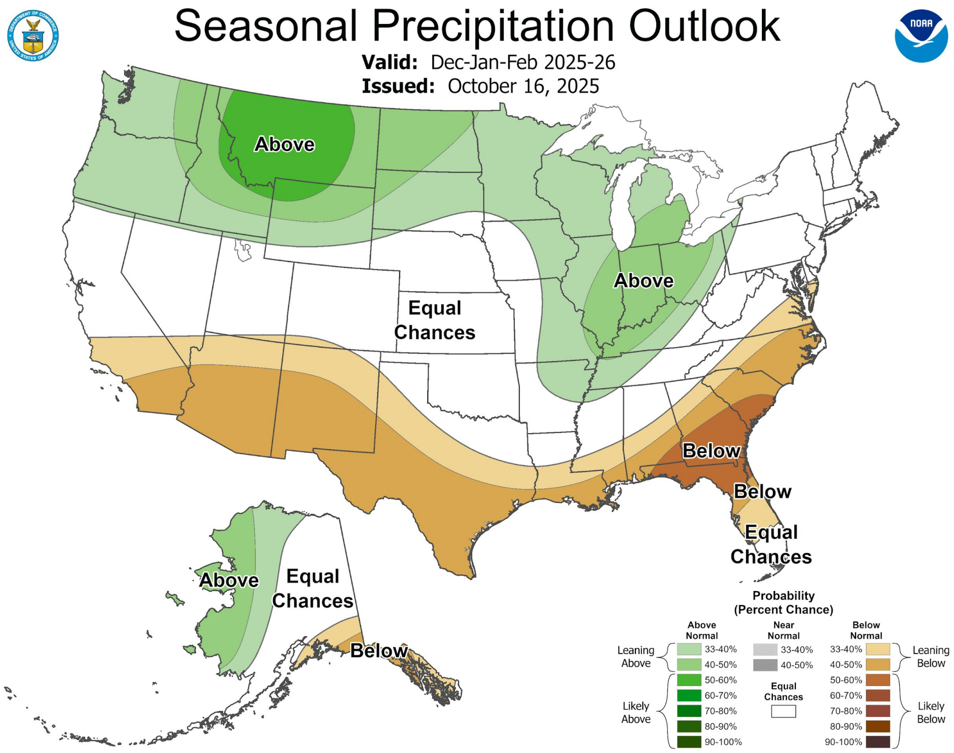
U.S. Seasonal Precipitation Outlook

December-January-February

- ➔ **Wetter-than-average** conditions are most likely over Montana, and above-average precipitation is also favored in northern and western Alaska, the Pacific Northwest, the **Northern Plains**, the Great Lakes region and Ohio River Valley.

- ➔ The greatest likelihood for drier-than-average conditions are over the far southeast U.S., but dryer-than-normal is favored across all of the southern tier States and southern Alaska.

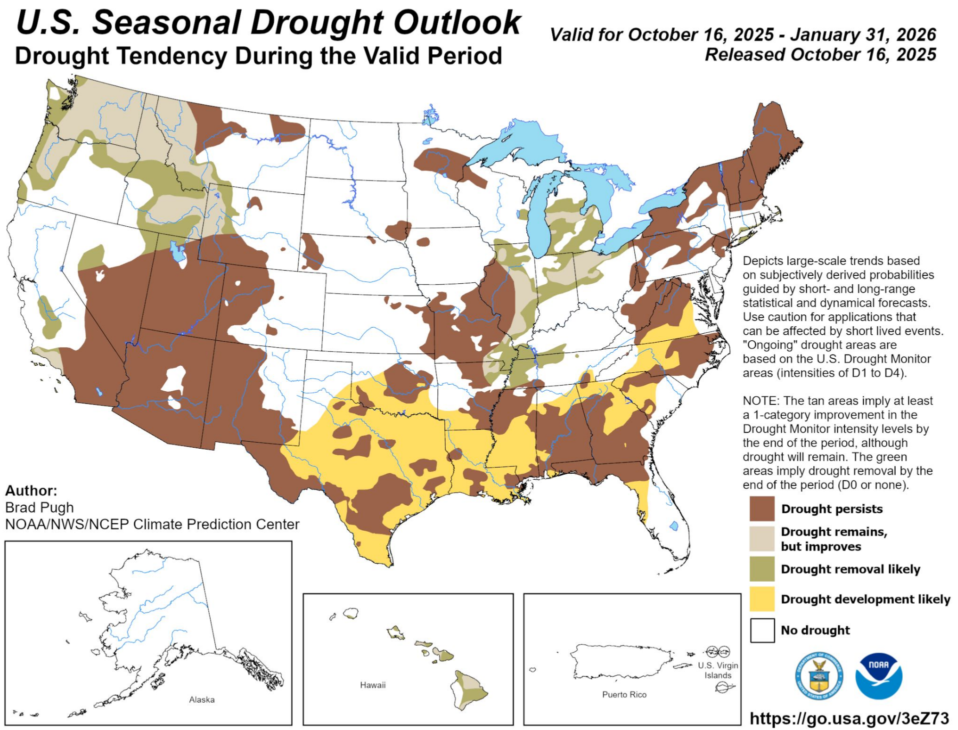
- ➔ The remaining areas have equal chances of below-average, near-average or above-average seasonal total precipitation.



U.S. Seasonal Drought Outlook

October 16, 2025-January 31, 2026

- ➔ Drought is expected to persist across the southwest, deep south, and portions of the northeast.
- ➔ Drought development is likely across the south central states
- ➔ Drought improvement is expected across the Pacific Northwest
- ➔ For central South Dakota and west central Minnesota no drought is expected

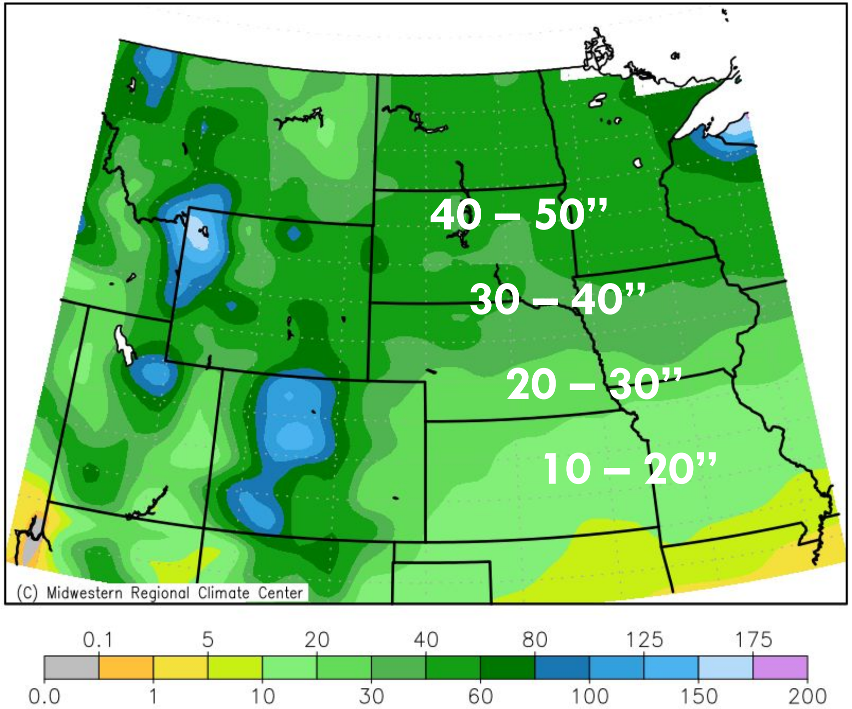


Local Discussion

Central & Northeast South Dakota & West Central Minnesota

- **<u>Keep In Mind:</u>** <u>The outlook does not project seasonal snowfall accumulations as snow forecasts are generally not predictable more than a week in advance.</u>
    - Normal seasonal snowfall values (image right) range from 30 to 50 inches across eastern South Dakota and west central Minnesota.
- The **winter outlook** for this season **favors colder than normal temperatures**.
    - This aligns with local studies indicate that ~77% of the time a weak La Niña event will result in colder than normal temperatures across our area.
- The **winter outlook** for this season favors **above normal precipitation**.
    - Local studies show precipitation odds are split between above and below normal for weak La Niña years.

Normal Seasonal Snowfall



Midwestern Regional Climate Center

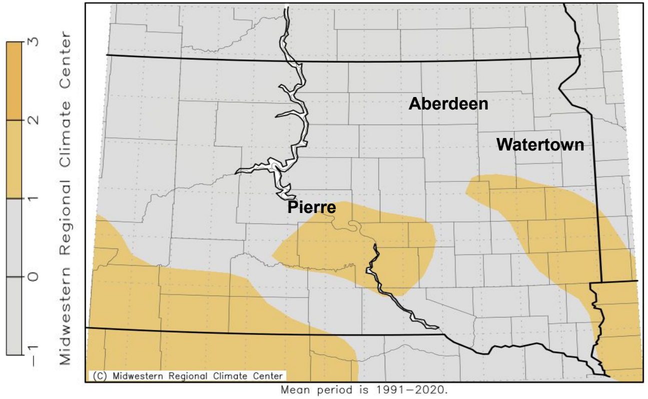
Past Summer (June-July-August) Pattern

➔ The cooler-than-normal temperature outlook for winter (December-January-February) would be a pattern change from summer (June-July-August) temperatures which ranged from near normal to a couple of degrees above normal.

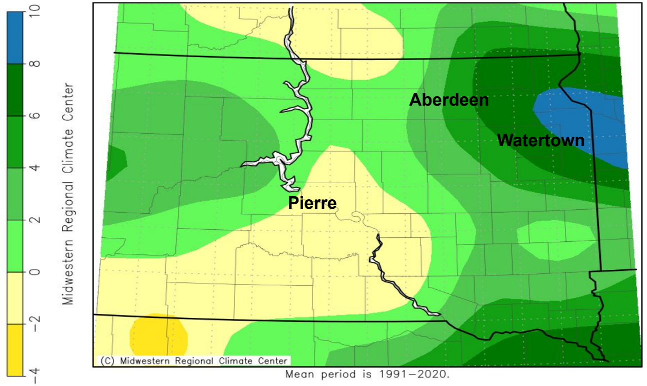
➔ Most of the region experienced a wet summer.
  - With the exception of south central South Dakota, northeast Campbell and northwest McPherson counties, summer (June-July-August) featured above normal precipitation.

➔ Northeast South Dakota and west central Minnesota received the most summer rainfall.
  - This area accumulated 4 to 10 inches above normal summer rainfall.
  - In fact, many locations experienced their **wettest summer on record** including: Britton, Watertown, Milbank, Sisseton, and Wilmot in South Dakota and White Rock Dam in Minnesota.

Departure from Normal Temperature (June-July-August)



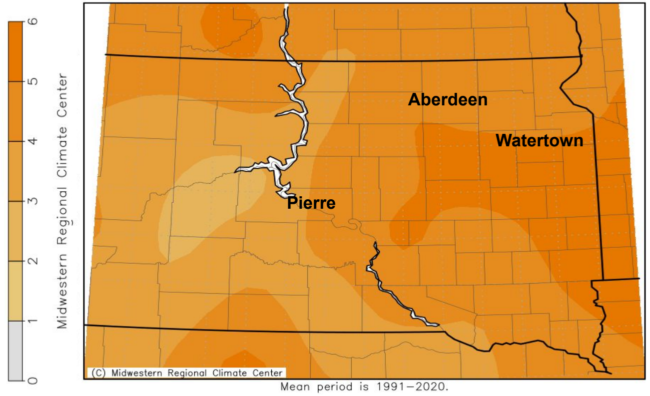
Departure from Normal Precipitation (June-July-August)



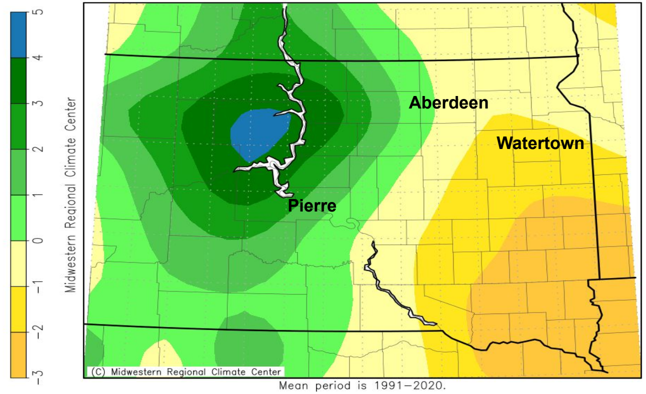
Current Fall Pattern (Last 45 Days)

- ➔ The entire region has experienced a warm start to fall.
- ➔ **Temperatures** have ranged from two to six degrees **above normal** over the **last 45 days** (Sept 1-October 15).
    - ○ The cooler-than-normal temperature outlook for winter (December-January-February) would be a pattern change from the last 45 day temperature trends.
- ➔ Central South Dakota has has above normal precipitation (1 to 5 inches above normal) in the last 45 days, while eastern South Dakota and west central Minnesota have ranged from 1 to 3 inches below normal for precipitation.

Departure from Normal Temperature (Setp 1 - Oct 15)



Departure from Normal Precipitation (Setp 1 - Oct 15)



Winter Preparedness

Regardless of what winter will ultimately bring for residents of the Northern Plains, now is the time to prepare!

Please join us in promoting winter weather safety now and during scheduled preparedness days:

- October 22: Winter Weather Preparedness Day in South Dakota
- November 17-21: Winter Weather Preparedness Week in Minnesota

The following resources can be used to help spread the winter safety message:

- https://www.weather.gov/safety/winter
- https://www.weather.gov/wrn/winter-sm

You can also follow us on social media and share our content when appropriate:

- x.com/NWSAberdeen
- www.facebook.com/NWSAberdeen

Winter Outlook 2025-2026

nws.aberdeen@noaa.gov

EXHIBIT 65

TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion

Facilities

Published on December 9th 2025 | CALGARY, Alberta

Highlights

- TransAlta to perform coal-to-gas conversion on its Centralia Unit 2 facility in Washington state, with a planned contracted capacity of 700 MW
- The converted facility will deliver reliable power to Puget Sound Energy under a long-term, 16-year fixed price contract through Dec. 31, 2044
- The project is currently projected to deliver a build multiple[1] of approximately 5.5 times
- The converted facility maintains TransAlta's position in its strategic core jurisdiction of the Pacific Northwest and extends the life of one of its legacy assets

TransAlta Corporation (TransAlta or the Company) (TSX: TA) (NYSE: TAC) is pleased to announce that it has signed a long-term tolling agreement (the Agreement) with Puget Sound Energy, Inc. (PSE) to convert its Centralia Unit 2 facility from coal to natural gas-fired generation. The Agreement provides a fixed-price capacity payment that provides PSE the exclusive right to the capacity, energy and ancillary service attributes of, as well as the dispatch rights to, the 700 MW facility.

"Our Centralia facility has a long history of providing reliable and affordable power in the Pacific Northwest region. We are pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers" said John Kousinioris, President and Chief Executive Officer.

"The facility is scheduled to cease coal-fired generation at the end of 2025, and the conversion to natural gas will lower the emission intensity profile of the facility by approximately 50 per cent. We are grateful for the constructive and solution-oriented engagement we have received from the Department of Ecology and other state and local regulatory bodies through the development of this project and we are well positioned to receive required regulatory approvals in a timely manner. This project demonstrates the valuable role that legacy assets can play in supporting the State's clean energy laws and system reliability in a cost effective and timely fashion," added Mr. Kousinioris.

“When the facility re-enters operations, it will generate long-term contracted cash flow for TransAlta, earning a full return on and of capital within the contract term. The Company is well positioned to execute this project given our deep technical, operational and engineering experience gained in previous coal-to-gas conversions,” concluded Mr. Kousinioris.

Approximately US$600 million of capital expenditures will be required to extend the useful life of the facility and convert it from coal to natural gas-fired generation, delivering an anticipated build multiple[1] of approximately 5.5 times. The target commercial operation date is late-2028 and the facility will operate until the end of 2044 under the terms of the Agreement. TransAlta anticipates declaring a final investment decision (FID) after receipt of all required approvals in early 2027. The Agreement is subject to customary regulatory approvals, including PSE receiving satisfactory approval from the Washington Utilities and Transportation Commission.

[1] Build multiple is a non-IFRS ratio which is calculated using capital expenditures and adjusted EBITDA[2]. We believe build multiple provides investors with a useful measure to evaluate capital projects. Readers are cautioned that our method for calculating build multiple may differ from methods used by other entities. Therefore, it may not be comparable to similar measures presented by other entities.

[2] Adjusted EBITDA is a non-IFRS measure. It does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Adjusted EBITDA is calculated by adjusting earnings before income taxes for certain items that may not be reflective of ongoing business performance. Please refer to the “Non-IFRS and Supplementary Financial Measures” section of our management’s discussion and analysis for the three and nine months ended September 30, 2025 (“MD&A”) for more information about the non-IFRS measures we use, including a reconciliation of adjusted EBITDA to earnings before income tax, the most directly comparable IFRS measure, which section of the MD&A is incorporated by reference herein. The MD&A can be found on SEDAR+ (www.sedarplus.ca) under TransAlta’s profile.

About TransAlta Corporation:

TransAlta owns, operates and develops a diverse fleet of electrical power generation assets in Canada, the United States and Australia with a focus on long-term shareholder value. TransAlta provides municipalities, medium and large industries, businesses and utility customers with affordable, energy efficient and reliable power. Today, TransAlta is one of Canada’s largest producers of wind power and Alberta's largest producer of thermal generation and hydro-electric power. For over 114 years, TransAlta has been a responsible operator and a proud member of the communities where we operate and where our employees work and live. TransAlta aligns its corporate goals with the UN Sustainable Development Goals and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. Our reporting on climate change management has been guided by the International Financial Reporting Standards (IFRS) S2 Climate-related Disclosures Standard and the Task Force on Climate-related Financial Disclosures (TCFD) recommendations. TransAlta has achieved a 70 per cent reduction in GHG emissions or 22.7 million tonnes CO2e since 2015 and received an upgraded MSCI ESG rating of AA.

For more information about TransAlta, visit our web site at transalta.com.

Cautionary Statement Regarding Forward-Looking Information

This news release includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable United States securities laws, including the Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "continue" or other similar words. In particular, this news release contains forward-looking statements about the following, among other things: contracted capacity of 700MW; build multiple; the facility's emission intensity profile; receipt of required regulatory approvals in a timely manner; expected capital expenditure; the target commercial operation date and the timing of a final investment decision with respect to the conversion.

Forward-looking statements and future-oriented financial information in this news release are intended to provide the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. Forward-looking statements are subject to important risks and uncertainties and are based on certain key assumptions. All forward-looking statements reflect TransAlta's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking statements, you should not put undue reliance on forward-looking statements and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to our most recent MD&A and the 2024 Integrated Report, including the section titled “Governance and Risk Management” in our MD&A for the year ended December 31, 2024, filed under TransAlta’s profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission at www.sec.gov.

Note: All financial figures are in Canadian dollars unless otherwise indicated.

For more information:

Investor Inquiries:	***Media Inquiries:***
Phone: 1-800-387-3598 in Canada and US	**Phone: 1-855-255-9184**
Email: investor_relations@transalta.com	**Email: ta_media_relations@transalta.com**

Download the full news release

Related Articles

December 04, 2024

TransAlta Closes Acquisition of Heartland Generation

May 03, 2021

TransAlta and Pembina Pipeline Announce 100 MW Renewable Power Purchase Agreement and Launch of the Garden Plain Wind Project

March 17, 2020

TransAlta Announces Acquisition of a Contracted Cogeneration Asset in Michigan

EXHIBIT 66

Announcement comes as company must take its coal-fired burner offline; 700 jobs expected at peak of construction, 40 to be employed permanently

(/uploads/original/20251210-164626-4a3-1transalata.jpg)

Steam rises from the TransAlta coal-fired plant at sunset in Centralia on Thursday, Oct. 27, 2023.

FILE PHOTO

Posted Wednesday, December 10, 2025 4:47 pm

By Jacob Moore / jacob@chronline.com

A long awaited natural gas conversion for the TransAlta power plant in Centralia is now in the works as the plant's last coal-fired generation unit prepares to go offline this month as part of a longstanding agreement with the state.

TransAlta announced Tuesday morning that the Lewis County-based coal-fired power plant will convert one of its two boilers to a natural gas-fueled generation system.

The burner that will be converted is currently scheduled to be shut down and cease burning coal at the end of the month as the last deadline included in a piece of 2011 legislation, which in part orchestrated the shutdown of the state's only remaining coal-fired power plant.

The company expects the converted facility to produce 700 megawatts of power each year. The company added that it is not considering any work to convert the facility's unit 1 coal-fired generation unit in the same way. That unit was decommissioned at the end of 2020, also in accordance with 2011 legislation mandating the closure.

"Our Centralia facility has a long history of providing reliable and affordable power in the Pacific Northwest region. We are pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers" TransAlta President and Chief Executive Officer John Kousinioris said in the announcement.

The company predicts that it will cost $600 million to convert the existing facility. It hopes to begin commercial operation of the converted facility by the end of 2028. The company says it expects to publish a final investment decision at the end of 2027 after both TransAlta and Puget Sound Energy receive all required approvals and permitting from the relevant regulatory agencies.

TransAlta staff said in response to questions asked by The Chronicle that its plans follow all existing regulatory rules, hinting that it expects its permits to be approved.

"The project is consistent with all federal, state and local laws, and no new legislation is required for it to proceed," the company said in a statement.

According to the TransAlta team, the company will soon submit permitting applications and will begin working through the regulatory process next year. At the same time, the facility will start early engineering and planned power outage work that will be necessary for the conversion.

The primary construction work, selection of a contractor to do the conversion and any other major decisions are expected to be announced after the facility has secured the necessary permits and regulatory approval. The company expects to begin major construction at the beginning of 2027 after the necessary approvals.

The work to convert the facility and all of the changes are expected to stay within the site's current footprint. Construction will start with retiring the old "coal-handling systems," replacing burners for natural gas combustion, installing a new water-bath heater and boiler, and replacing the existing cooling towers.

The company says it expects to continue using most of the major infrastructure already in the facility. The main boiler, turbines and electrical transmission systems used previously will continue to be used. The facility will need to install a new 1,500-foot underground natural gas pipeline to connect the facility to an existing natural gas pipeline.

Construction and conversion work for the facility will require all hands on deck. Conversion is expected to create up to 700 temporary jobs at the peak of the work. Once finished and operating as normal, the facility will require roughly 40 people to operate day-to-day.

That represents a continued reduction in workforce at the facility for a site that once employed hundreds of people and laid off more than 60 employees when its first boiler went offline in 2020.

In the past, the company has raised concerns over the economic side of converting to natural gas, painting it as uncertain. According to TransAlta staff, the conversion is made possible in part by the agreement with PSE and in part because the reuse of parts in the current facility will cut down on costs, especially when compared with the cost of constructing a new facility.

“The Tolling Agreement provides long-term contracted cash flow through 2044,” reads a statement from the company. “By utilizing and repurposing existing infrastructure, the conversion is a cost-effective, lower-emission solution compared to building a new facility and supports regional grid reliability.”

However, the site remains uncertain until TransAlta and PSE receive the necessary approval from regulatory agencies. Its future beyond the agreement with PSE’s end date in 2044 means it is especially uncertain as a long-term energy production facility.

Local stakeholders are observing the development with cautious optimism.

Lewis County Public Utility District (PUD) General Manager David Plotz said he was excited to see the progress being made, but added the PUD would wait to make plans based on the conversion until permitting and other regulatory hurdles have been overcome.

Washington state Sen. John Braun, R-Centralia, has seemingly expected the news. He hinted at the natural gas conversion in early November during a legislative forum in Chehalis.

“The reality is you can't get from where we are today to where we want to be in the future with clean energy without somewhere between six and 12 gas plants,” Braun said during the November forum. “One

During the same meeting, Braun also signaled his belief that the plant was unlikely to be an intergenerational solution to energy in the area. Instead, he suggested the plant would be a good candidate for a small nuclear reactor, adding that natural gas could be a stop gap between coal and nuclear energy.

“The state, Energy Northwest and Puget Sound Energy has invested heavily in building a small nuclear reactor at the Hanford site but for the Tri-Cities,” Braun said. “We need to do the work to rally support for that based on new, current technology, and get that at the TransAlta site. We do that, we do that in the next couple years, so that we're all ready, we're ready to build right after they build in Hanford. That's the long-term solution.”

OTHER ITEMS THAT MAY INTEREST YOU

How are bald eagles faring after Western Washington floods? What to know (/stories/how-are-bald-eagles-faring-after-western-washington-floods-what-to-know,394181)

Microsoft scoops up Redmond office space before RTO deadline (/stories/microsoft-scoops-up-redmond-office-space-before-rto-deadline,394180)

Washington state flu cases rising, while national vaccine guidance shifts (/stories/washington-state-flu-cases-rising-while-national-vaccine-guidance-shifts,394178)

Apartment manager accused of voter fraud, using ballots of ex-renters in Eastern Washington (/stories/apartment-manager-accused-of-voter-fraud-using-ballots-of-ex-renters-in-eastern-washington,394177)

EXHIBIT 67
Part 1
(Introduction through page 15)

NOVEMBER
2024

BEST PRACTICES IN INTEGRATED RESOURCE PLANNING

A guide for planners developing the electricity resource mix of the future

Synapse
Energy Economics, Inc.

BERKELEY LAB

Principal Authors

Synapse Energy Economics
Bruce Biewald
Devi Glick
Shelley Kwok
Kenji Takahashi

Lawrence Berkeley National Laboratory
Juan Pablo Carvallo
Lisa Schwartz

Acknowledgments

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Contributors:
Form Energy
Rachel Wilson

Synapse Energy Economics
Rose Anderson
Bob Fagan
Joe Hittinger
Alice Napoleon
Jack Smith (formerly of Synapse)

University of Texas, Austin
Nina Hebel
Benjamin Leibowicz

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Natalie Mims Frick, Lawrence Berkeley National Laboratory

Joseph Paladino, DOE Office of Electricity

Paul Spitsen, DOE Office of Energy Efficiency and Renewable Energy

Rodrigo Cejas Goyanes, DTE Energy

Shayla D Manning and Laura Mikulan, DTE Energy

Mike Sontag, Energy and Environmental Economics

Anna Sommer, Energy Futures Group

Ryan Fulleman, Rachel Moglen, and Nidhi Santen, Electric Power Research Institute

Priya Sreedharan and Taylor McNair, GridLab

Jeff Loiter, National Association of Regulatory Utility Commissioners

Elaine Hale, National Renewable Energy Laboratory

JP Batmale and Kim Herb, Oregon Public Utility Commission

Elizabeth Hossner, Kaitryn Olson, Phillip Popoff, Andrea Talty, and Tyler Tobin, Puget Sound Energy

Carl Linvill, Regulatory Assistance Project

Tyler Fitch, RMI

Jeremy Fisher, Sierra Club

Michele Beck, Utah Office of Consumer Services

Kathi Scanlan, Washington Utilities and Transportation Commission

Gwen Farnsworth, Sydney St. Rose-Finear, and Clare Valentine, Western Resource Advocates

Contents

Executive summary

In 2013, Synapse Energy Economics prepared a report on best practices in integrated resource planning (IRP) for electric utilities (Synapse 2013). In the decade since, the U.S. electricity sector has been in transition. Many aging fossil fuel plants retired as operational costs increased and environmental regulations placed pressure on power plant air emissions and water pollutants. Renewable energy resources were deployed at an increasing pace due to declining costs and favorable policies and incentives. Electrification of transportation and buildings, and greater deployment of distributed energy resources, began to impact utility assessments of grid needs.

While electricity loads grew just 2.6 percent between 2014 and 2023, we are now entering a period of projected load growth with rapid expansion of data centers and industrial and manufacturing loads, in addition to increasing loads from electrification. Utilities, regulators, and regional grid operators are wrestling with the challenges this presents in terms of affordability, sustainability, reliability, and resilience.

The trend toward increasing loads coincides with a temporary slowdown in renewable energy deployment as the industry recovers from inflation and supply chain challenges. Some utilities have responded with plans to extend the lives of potentially uneconomic coal plants or add new natural gas assets over the next 5 years, or both. This may extend reliance on resources that many states seek to phase out to achieve decarbonization and other electricity transition goals. At this turning point, robust and forward-thinking IRP is as important as ever to ensure utilities can meet the needs of their customers while continuing to work toward broader commitments utilities have made to communities and regions in which they operate.

This guide updates and expands the recommendations in Synapse's earlier report and outlines IRP best practices for electricity systems undergoing a major transition. The guide is for resource planning professionals and stakeholders involved in resource planning processes. This diverse group of people includes utility personnel tasked with conducting resource planning and making investment decisions, state regulatory commissions that develop planning guidance and oversee the resource planning process, and stakeholders that represent a wide range of interests—utility consumer advocates, environmental groups, industrial customers, local governments, independent power producers, and many others.

Definition: Integrated Resource Plan

An IRP is a power system plan for a vertically integrated electric utility’s power system plan for to meeting forecasted electricity demand over a specified future period.

- The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders.
- The objective of an IRP is to demonstrate which resource portfolio —including supply- and demand-side options—is most likely to be optimal in the face of risks and uncertainties.
- IRPs provide information on electricity system costs, risks, reliability, and trends and answer important questions that affect electricity consumers and utility investors.

The recommendations in this guide are informed by our experience working with a variety of these audiences and our extensive review of IRP reports and proceedings. The utility-specific examples we cite throughout this guide serve to illustrate both best practices and shortcomings; they are not endorsements or indictments of specific utilities. Instead, the examples are intended to provide clarity on practices we recommend or discourage. We aim to be comprehensive in the topics we cover and best practices we offer. The best practices we recommend are based on our collective experience; they are not the only reasonable approaches to various aspects of resource planning.

The guide offers 50 best practices across the following components of the IRP process:

- Designing a transparent and inclusive stakeholder engagement process
- Integrating resource adequacy
- Developing robust model inputs
- Designing scenarios and sensitivities
- Running the models
- Evaluating and communicating results
- Integrating IRP processes with other planning processes, procurement, and utility proceedings

Each best practice includes explanations and examples. Some recommended IRP approaches represent current best practice, while others are aspirational for future improvement. The following checklist summarizes all of these recommended practices.

Best Practice Checklist

I. Stakeholder engagement

- **Best Practice 1:** Use an inclusive stakeholder process
- **Best Practice 2:** Engage technical stakeholders in IRP modeling

II. Resource adequacy

- **Best Practice 3:** Link resource adequacy assessments with resource planning
- **Best Practice 4:** Apply consistent accreditation frameworks to all resource types
- **Best Practice 5:** Use a regional perspective to plan for resource adequacy

III. Developing model inputs

- **Best Practice 6:** Use up-to-date inputs and assumptions
- **Best Practice 7:** Recognize historical data limitations

Load Inputs

- **Best Practice 8:** Develop a load forecast for the expected future
- **Best Practice 9:** Incorporate load flexibility into electrification forecasts
- **Best Practice 10:** Plan ahead for large growth
- **Best Practice 11:** Transparently represent distributed generation and storage

Supply-side resource inputs

- **Best Practice 12:** Use accurate assumptions for the costs of new resources
- **Best Practice 13:** Represent the full cost and risk of advanced technologies
- **Best Practice 14:** Include realistic assumptions about resource availability timing, without unnecessary constraints
- **Best Practice 15:** Limit renewable integration cost adders
- **Best Practice 16:** Model all avoidable forward-going resource costs
- **Best Practice 17:** Model battery energy storage options
- **Best Practice 18:** Be consistent in treatment of emerging technologies

Demand-side resource inputs

- **Best Practice 19:** Ensure thoughtful and consistent assumptions for demand-side resources
- **Best Practice 20:** Model and bundle demand-side resources carefully
- **Best Practice 21:** Ensure consistency with IRP scenarios
- **Best Practice 22:** Incorporate all relevant benefits for demand-side resources

Market inputs

- **Best Practice 23:** Use reasonable market interaction assumptions

Fuel and commodity inputs

- **Best Practice 24:** Model fuel supply limitations
- **Best Practice 25:** Evaluate the impacts of gas price volatility and coal supply constraints

Transmission inputs

- **Best Practice 26:** Consider transmission alternatives and infrastructure expansion
- **Best Practice 27:** Properly justify bulk power system interconnection costs and constraints

IV. Designing scenarios and sensitivities

- **Best Practice 28:** Model a base case that allows for easy comparison
- **Best Practice 29:** Design scenarios to evaluate uncertainty and risk
- **Best Practice 30:** Plan for and incorporate important regulatory factors

V. Running the models (and iterating)

- **Best Practice 31:** Thoughtfully select capacity expansion and production cost models
- **Best Practice 32:** Thoughtfully select a geographic model scale
- **Best Practice 33:** Thoughtfully define the appropriate study period
- **Best Practice 34:** Thoughtfully select the appropriate time granularity for production cost modeling
- **Best Practice 35:** Calibrate the production cost and capacity expansion models
- **Best Practice 36:** Let optimization models optimize
- **Best Practice 37:** Base power plant retirement decisions on forward-looking costs
- **Best Practice 38:** Use modeling parameters that capture the value of battery energy storage
- **Best Practice 39:** Use stochastic approaches for robust portfolio creation
- **Best Practice 40:** Use the models iteratively

VI. Evaluating portfolio results and communicating transparently to regulators and stakeholders

- **Best Practice 41:** Use appropriate metrics to evaluate IRP results
- **Best Practice 42:** Report results clearly
- **Best Practice 43:** Benchmark inputs and results to other utilities
- **Best Practice 44:** Select a preferred portfolio
- **Best Practice 45:** Model state goals and priorities in preferred portfolio

VII. Integrating the IRP process with other utility proceedings

- **Best Practice 46:** Use IRP results to inform an Action Plan and utility procurement processes
- **Best Practice 47:** Use IRP results to inform planning for bulk power systems
- **Best Practice 48:** Evaluate bill impacts
- **Best Practice 49:** Consider energy justice comprehensively
- **Best Practice 50:** Consider the evolving natural gas distribution industry

Introduction

What is integrated resource planning and why is it important?

An integrated resource plan (IRP) is a roadmap for meeting forecasted electricity demand over a specified future period, historically focused on the bulk power system.[1,2] Many vertically integrated utilities in the United States, including investor-owned, municipal, and rural cooperative utilities, conduct IRP processes. Regulated utilities—investor-owned as well as cooperative utilities in some states—file these plans with public utility commissions under state guidance. Other cooperative utilities and municipal utilities submit plans only to their governing boards.

The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders and regulators. The objective of an IRP is to demonstrate which resource portfolio is most likely to be least cost in the face of risks and uncertainties. IRPs provide regulators and stakeholders with information on electric system demand, reliability, costs, risks, and uncertainties and other important issues that affect utility customers.

Robust resource planning is critical for utilities to make investment decisions that are reasonable, prudent, and in the public interest. Poor utility resource investment decisions can burden customers with electricity costs that are higher than necessary, lead to over- or under-procurement of resources, disrupt achievement of state policy goals, and forego solutions to contain costs and risks in the future. Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers, while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.

IRP processes emerged from least-cost planning in the late 1980s when concerns over fuel price volatility and bulk power reliability prompted states to require electric utilities to examine prudency and affordability of investments, among other issues. A majority of states today require regulated electric utilities to file IRPs (Figure 1). Some states require utilities to file less comprehensive long-term plans. In Florida, for example, utilities must file Ten Year Site Plans every year, but these plans do not include capacity expansion or optimized portfolio modeling. In addition, some utilities file IRPs to meet requirements of federal power marketing agencies (National Archives, n.d.), and some utilities voluntarily file IRPs. While IRPs are not

> ***Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.***

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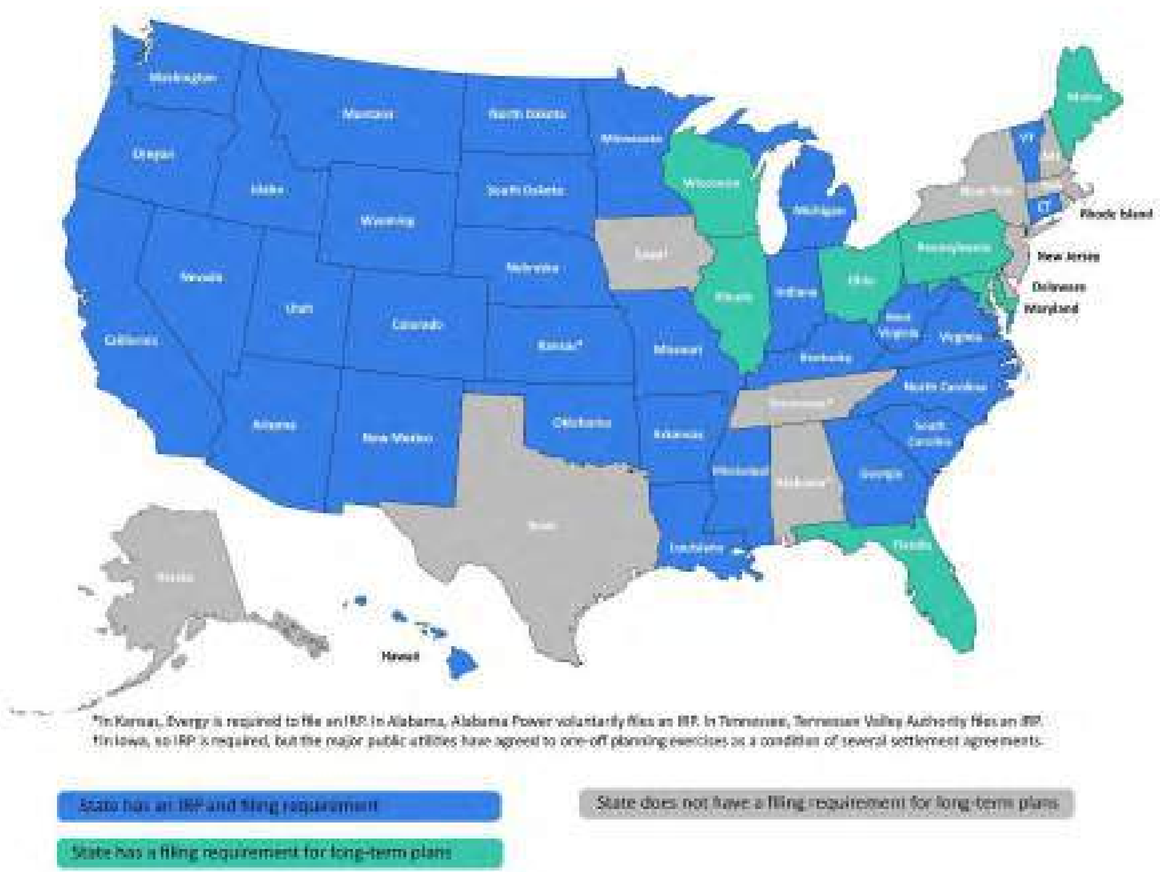
[1] Some jurisdictions are implementing or investigating Integrated System Planning approaches. For example, Hawaiian Electric filed its first Integrated Grid Plan in 2023 to harmonize distribution, transmission, and generation planning through iterative modeling. In 2023, Salt River Project in Arizona published its first Integrated System Plan. Public Service of Colorado is working to integrate modeling and planning across electric generation, transmission, and distribution, as well as natural gas. Washington state requires its large dual-fuel utility, Puget Sound Energy, to file an Integrated System Plan by 2027 (RCW 80.86.020(4)).

[2] The electricity industry often uses the term "IRP" to refer to both the resource planning process and the resulting resource plan filing. In this report, “IRP” refers to the plan and "IRP process" describes the process that results in the plan.

required in all states, lessons from quality IRP processes are applicable across all utility planning processes.

Figure 1. States with integrated resource planning or similar processes as of November 2024



An IRP process is also a vehicle for planning, oversight, and feedback. The basic framework is the same across most states: The utility performs modeling and analysis with input from stakeholders and communities, synthesizes the results into a written plan, and submits it to state regulators for review. Utility customers and other stakeholders have an opportunity to provide input, and the utility can move forward with a plan that is informed by stakeholder input and some amount of regulatory review and oversight. The ideal process is one that is mutually beneficial for both the utility and the public.

The rules that govern IRP processes vary by state (RMI 2023). The required filing frequency varies from 1 to 5 years. The planning horizon required for most IRPs spans 10 to 20 years, although some utilities plan out as far as 40 years. Many states require utilities to include a near-term (2 to 5 year) action plan.

Regulatory action from state commissions on IRPs varies, from accepting that the plan meets filing requirements—with any deficiencies noted (e.g., Mississippi), to acknowledging that the plan seems reasonable at the time (e.g., Oregon, Utah), to approving or rejecting the plan (e.g., Colorado, Georgia, Nevada). A commission's decision on the IRP typically carries weight in cost recovery proceedings such as general rate cases that determine the revenue the utility may collect through customers' electricity rates.

In some states, IRP and resource procurement processes are tightly coupled (e.g., Nevada, Colorado, and Minnesota); in other states, they are more distinct processes (LBNL 2021a). Procurement processes can provide current input data for use in IRP modeling. Although an IRP establishes a resource investment plan, real-world changes such as equipment failure, new regulations, and changing market trends often demand adjustments and deviations in resource procurement from what was planned.

Utilities have considerable latitude in the way that they conduct IRP modeling and present results. Further, IRP technical complexity and asymmetries of information make oversight difficult. Nevertheless, state utility regulators and stakeholders can take concrete actions to support IRPs that are consistently well conducted. Enabling such engagement requires that planning processes are transparent and inclusive, state planning objectives are explicit, and utility models and methods are up to date and rigorously applied.

What has changed in the last decade?

Synapse authored a report on IRP best practices in 2013 (Synapse 2013). In the decade that followed, the U.S. electric power landscape changed substantially. This updated and expanded guide addresses a multitude of changes that could lead to a large buildout of the electricity system in the future. The potential for such a buildout places new urgency on the need for quality long-term resource planning. Without quality planning, we risk short-sighted and inefficient investments that impede the optimal buildout of the utility system. Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.

The main drivers of change over the past decade include low natural gas prices, falling prices for renewable and other low-carbon energy resources, significant growth in variable energy resources, advances in generation and grid management technologies, increased use of distributed energy resources for grid services, increasing frequency and severity of extreme weather events, fuel price volatility, inflation and supply chain disruption, interconnection queue challenges, decarbonization goals and targets, and environmental regulations.

> ***Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.***

Looking forward, we expect to see many of these trends continue. We also expect acceleration of current trends due to electrification of transportation and buildings, growth in data center loads and other end uses driven by artificial intelligence (AI) as well as manufacturing, retirement of coal plants and reduction of coal supply, changing capacity accreditation[3] frameworks for resources, changes in renewable energy prices, integration and interconnection challenges with increased deployment of wind and solar, and development of new carbon-free technologies. In addition, there will always be changes we cannot predict. IRPs can build in flexibility to reevaluate resource acquisition strategies over time and make resource decisions closer in time to projected needs.

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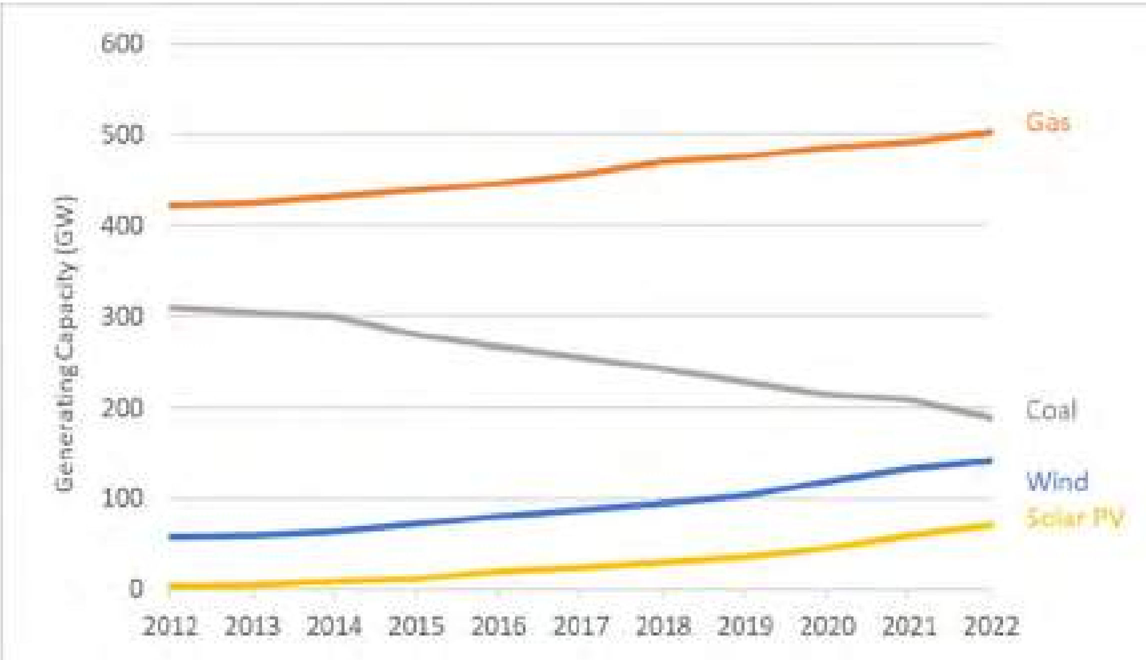
[3] Capacity accreditation is the process of measuring and assigning a value to a resource that represents its contribution to resource adequacy and reliability on an electricity system. NERC defines resource adequacy in its Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."

The electricity resource mix has changed dramatically since Synapse's 2013 report (Figure 2). That year, the United States was in the midst of a shale gas revolution that enabled an industry-wide move from coal to gas (U Michigan 2014). Gas, wind, and solar capacity has continued to grow over time, increasing the shift away from coal (U.S. EPA 2022). Until recently, electric utility demand was in a two-decades-long period of relatively flat load growth. In the last decade (2014–2023), electricity demand grew just 2.6 percent (U.S. EIA 2024a).

Figure 2. Utility-scale electric generating capacity for selected resource types in the United States



Source: U.S. Energy Information Administration. 2024. "Sales of Electricity to Ultimate Customer: Total by End-Use Sector, 2014-March 2024," Table 5.1. https://www.eia.gov/electricity/monthly/xls/table_5_01.xlsx.

Technology innovation also has had a significant effect on resource costs over the last decade—for example:

- New renewable energy technologies and economies of scale have reduced the cost of wind and solar precipitously. They are now often the least expensive new resources available on a per megawatt-hour (MWh) of energy basis (NREL 2021a). In 2022, renewable power generation exceeded coal generation for the first time in U.S. history, and renewable resources now produce 21 percent of annual generation (U.S. EIA 2023c).
- Utilities are deploying cost-competitive utility-scale batteries across the country to help meet peak demand, mitigate short-term changes in solar and wind supply, and provide ancillary services (Martucci 2024).
- Grid modernization advancements, such as advanced metering infrastructure paired with time-varying rates and control technologies, microgrids, and distributed generation and storage, have increased visibility into and management of end-use energy consumption, providing utility

customers with new opportunities for demand flexibility to reduce energy bills and provide grid services (Deloitte 2022).

Federal and state policies and regulations also affect the resource mix. For example, the *Inflation Reduction Act of 2022* (IRA) introduced multiple federal incentives to modernize and decarbonize the electric grid. In another example, the Federal Energy Regulatory Commission (FERC) Order 1920 is intended in part to ease access to remote, low-cost resources such as wind and solar. In addition, large utility customers in the private and government sectors are increasingly purchasing low-carbon energy resources, and many utilities are integrating corporate decarbonization goals into their planning processes (LBNL 2019a).

These advances appear against a backdrop of new challenges (EPRI 2023b):

- The interconnection queue for new resources has grown tremendously, creating a deployment bottleneck and slowing down the pace of deployment of new wind and solar resources in many regions (LBNL 2023d).
- Inflation, tariffs, and supply chain challenges stemming from the COVID-19 pandemic disrupted the steady downward trend in renewable energy costs and created a relatively short-term period of stagnation in price decline trends (LBNL 2023c).
- Extreme weather events driven by climate change, including extreme heat, severe and prolonged cold snaps, raging storms, and wildfires, have revealed the fragility of power grids and prompted new efforts by utilities to better understand resource adequacy needs to boost resilience and improve capacity accreditation methods (FERC 2023).
- A rapid rise in data center load growth driven by AI and an increase in industrial and manufacturing investments add risks for resource planning (Grid Strategies 2023). Coupled with trends in electric vehicle (EV) adoption, building electrification, and integration of planning across the bulk power and distribution systems, utilities are facing a new paradigm for planning (IEA 2024; NREL 2021b).
- Retirements of coal units are accelerating along with deployment of renewable energy, driven in part by state and federal environmental regulations and incentives (S&P Global, n.d.). This creates new challenges for reliability and grid planning and requires increased investment in transmission, firm flexible resources (such as battery storage), and grid management technologies.

Age-old challenges also continue in new contexts. For example, Americans have weathered multiple periods of fossil fuel price shocks. Most recently, the 2022 Russian invasion of Ukraine impacted gas supply and prices (Maneejuk, Kaewtathip, and Yamaka 2024). The domestic coal industry has wrestled with dwindling demand, labor challenges for mines and transportation, and constriction and consolidation of coal supply ownership (PA Consulting 2023). Such challenges highlight the importance of understanding risks associated with fuel price volatility (Amy 2023) and spending large amounts of capital to maintain aging, potentially uneconomic power assets (EIPT 2023). Another challenge is the cost of new infrastructure that may be needed for fuel delivery and storage. These issues underscore the importance of robustly evaluating the economics of retirement and replacement of legacy generating units.

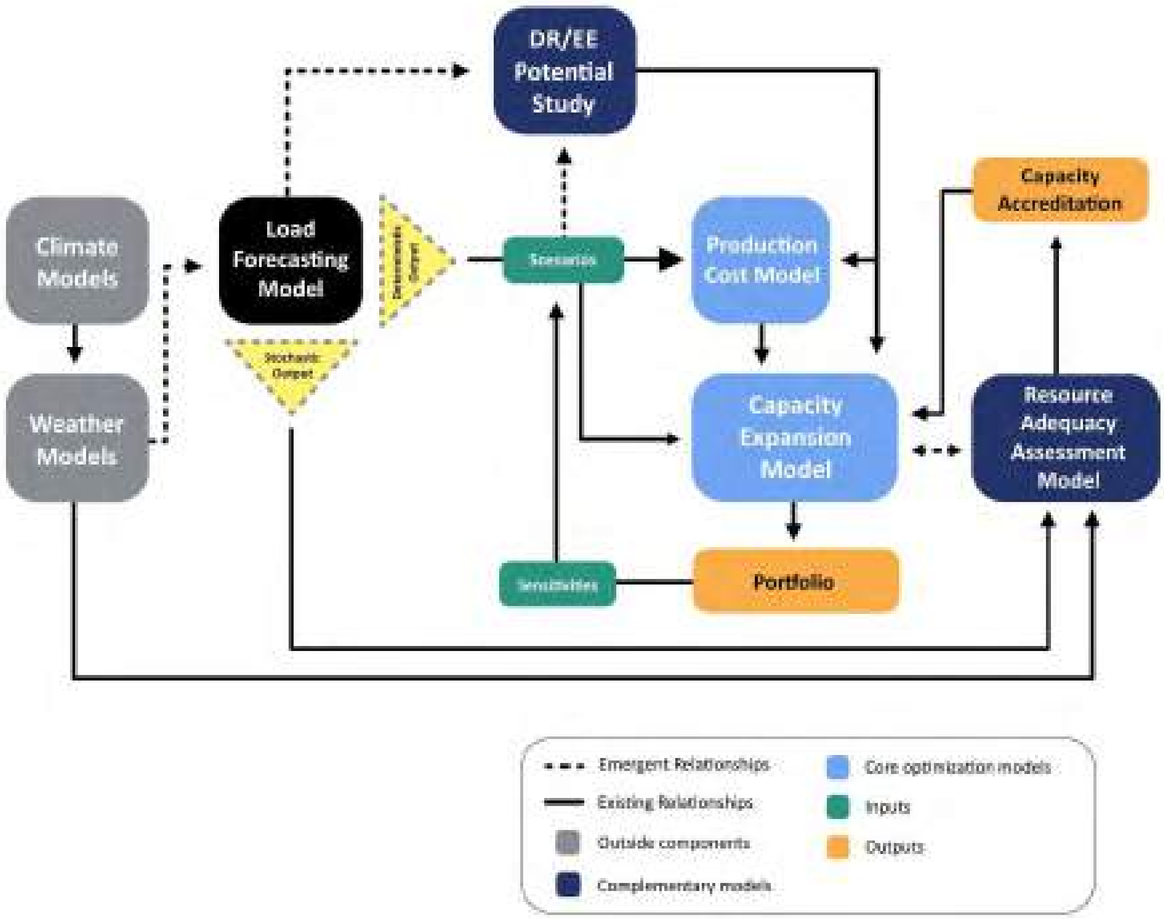
Thoughtful and robust long-term planning is needed more than ever. In this moment of rapid, widespread changes affecting both supply- and demand-side resources, the planning tools and strategies of the past do not match the scale and pace of today's needs. Emerging best planning practices can help tackle these challenges by providing a wide range of tools for navigating this transition and positioning utilities to evolve and adapt as energy systems and markets continue to change.

The role of modeling in IRP

Modeling is a core tool of the IRP process that informs utility planning decisions. To achieve multiple planning objectives, the utility can choose the most appropriate models and run them with accurate and transparent inputs. At the same time, some input data may be sensitive to the company's confidential business strategy or financial decisions. Planners can pair modeling tools with rigorous analysis, critical thinking, and creativity, using judgment and good sense throughout the modeling process.

IRP processes use many types of models to generate different types of forecasts. Figure 3 illustrates a typical IRP modeling structure. Planners conduct separate studies when necessary to generate forecasts, which become key input parameters into other models. For example, one model may forecast fuel prices or new resource costs, which may in turn feed into models that simulate generation unit economics. Reliability modeling helps to determine the reserve margin and other reliability metrics that a utility must meet and to assess capacity accreditation for different resource types. Planners may use additional models to determine key input parameters such as potential and costs for energy efficiency and demand response resources.

Figure 3. Example of a typical model structure used in IRP processes and current (solid line) and potential (dashed line) interdependence



Note: DR refers to demand response. EE refers to energy efficiency.

Descriptions of modeling in this guide primarily focus on capacity expansion and production cost modeling, which lie at the center of the modern IRP process. These two techno-economic modeling steps are increasingly integrated and performed in an iterative manner. Integration of these models with resource adequacy assessment models is an aspirational practice to develop robust least-cost portfolios.

The capacity expansion model simulates the current system, then determines the optimal, least-cost schedule to retire, build, and run generation and storage units as well as demand-side resources. These decisions usually occur on an annual basis. This first model is called "capacity expansion" because the model can add new resources and retire existing ones. The goal of the model is to build a least-cost system that meets projected loads, subject to reliability constraints and policy requirements such as state renewable portfolio standards.

The production cost model optimizes a candidate resource portfolio for least-cost operations, capturing economic dispatch, unit commitment, ancillary service requirements, and other technical constraints at an hourly or sub-hourly basis. This simulation of the economic operation of the power system is often much more temporally and spatially detailed than simulation by the capacity expansion model.

Production cost modeling provides detailed results on system cost, operations, emissions, variable energy curtailment, and other key metrics and outputs.

At its core, capacity expansion and production cost modeling are about minimizing system costs subject to constraints. The extent to which a modeler allows the model to optimize, and the information the modeler feeds the model for that purpose, are critical for achieving useful IRP results.

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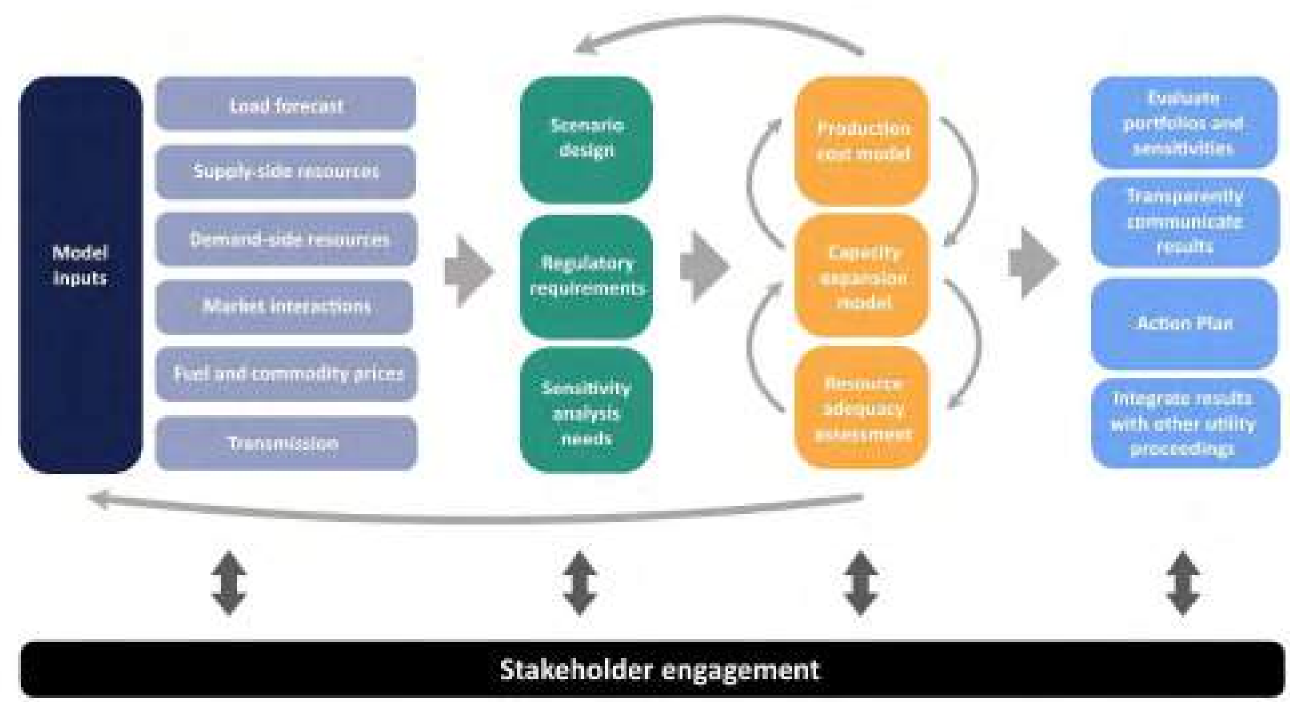
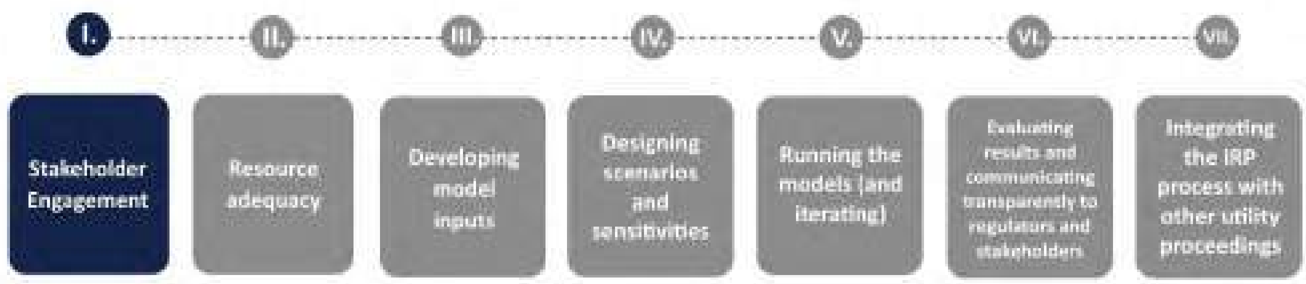
Overview of Report

The rest of this guide describes both current and emerging best practices in IRP. The guide mirrors the order of a typical IRP process. Figure 4 depicts the typical IRP process flow, including how modeling interacts with other steps of the process, such as stakeholder engagement. The report begins by outlining the requirements for a robust stakeholder engagement process. We then summarize best practices for integrating resource adequacy into IRPs. Next, we present best practices related to developing robust model inputs, designing scenarios and sensitivities, and running the model. Then, we discuss how to evaluate and communicate portfolio results. We end with a discussion of how to integrate IRP processes with other utility planning processes and proceedings.

Figure 4. Typical IRP process flow diagram



I. Stakeholder engagement



The first two best practices in this guide focus on how to engage stakeholders in the IRP process. We provide suggestions for making the process inclusive for a wide audience as well as ensuring that technical stakeholders have the tools necessary to participate in the modeling process.

Best Practice 1. Use an inclusive stakeholder process

Develop an inclusive stakeholder engagement process that balances access and transparency with reasonable time commitments.

Vertically integrated electric utilities provide essential energy and delivery services to a captive customer base through a monopoly business model, while operating in a highly technical and complex field. To ensure that utility decisions are fair and robust and based on reasonable evidence, meaningful stakeholder engagement (RMI 2023), regulatory oversight, and participation of technical experts working on behalf of stakeholders are essential in the IRP development process. A well-developed stakeholder engagement process provides access to all stakeholders who have a reasonable interest and stake in the utility decision-making process— including those who have traditionally been underrepresented in these processes.

An effective IRP process includes regular stakeholder meetings that allow participation and engagement throughout the IRP process, from input development through scenario development and modeling, review of results, selection of the preferred portfolio, and development of the action plan. The utility engages stakeholders early in the process, on a timeline and in a manner that allows for meaningful feedback. The following elements represent a set of minimum practices for an effective stakeholder engagement process:

Process and design elements

- The utility develops a charter or document clearly outlining the rules, norms, and any other relevant details for the stakeholder engagement process, with buy-in from stakeholders to align expectations for all parties.
- Facilitators, technical consultants, or an internal communications team moderate stakeholder sessions and technical conferences.

- Materials, including an agenda and slides to be presented, are available in advance of each stakeholder meeting and technical conference so stakeholders have time to review the information, prepare for planned topics, and provide productive input.
- A formal discovery process allows stakeholders access to data, assumptions, results, and any other information that the utility does not directly offer.
- The process elicits stakeholder feedback during stakeholder meetings and technical conferences, as well as through a formal commenting process, with clear deadlines for providing input.
- Utilities provide formal responses to stakeholder feedback, adhering to clear deadlines for responding to stakeholder comments. Responses clearly address which feedback is being adopted and how, and which is not and why.

Removing barriers to participation

- Stakeholder sessions accommodate remote access to enable as many stakeholders as possible to participate, including members of the public and underrepresented groups.
- The stakeholder process design considers and accommodates stakeholders' needs and challenges such as language, schedules, and economic barriers.
- Technical education sessions, offered and open to all, provide core education on the IRP process (as needed/requested by stakeholders).
- Stakeholder sessions occur regularly enough to allow for meaningful input and participation throughout the development of the IRP, without being so time-intensive and burdensome that only a handful of people can fully participate.
- Intervenor compensation funds designate and otherwise approve stakeholders to formally participate in public utility commission (PUC) proceedings, addressing barriers to participation and engagement of technical experts for many stakeholders. Such funding typically requires action by state legislatures and utility regulators.

Transparency

- The IRP process engages stakeholders throughout, including:
    - Before modeling begins to propose scenarios and inputs and provide feedback on what is being modeled and how;
    - During modeling to provide input on results; and
    - After the draft plan is released to provide input on how the utility used the results to create an action plan.
- Transparency is a priority, with the utility sharing all input data, modeling assumptions, scenario and sensitivity designs,[4] modeling files, and modeling results as they become available–as well as any other information necessary for stakeholders to have a comprehensive understanding of how the IRP was developed. This may include sharing utility spreadsheets used for pre-

[4] As discussed in Section VI, a scenario is a model run with a specific set of input assumptions and constraints. A sensitivity changes a single key input to understand how that input affects or drives results, often across multiple scenarios.

processing of data and post-processing of results so stakeholders can see how the utility used both input and outputs.

- The utility shares data, inputs, and results for its preferred portfolio and all major scenarios and sensitivities–not just for one base scenario.[5]
- The utility only requires non-disclosure agreements (NDA) when necessary to protect data that is truly a utility trade secret or that the utility holds under a third-party NDA (e.g., fuel and market price forecasts) to avoid unnecessarily hindering stakeholder engagement.[6]

Technical engagement

- The process allows stakeholder-funded technical experts to participate and contribute essential technical expertise.
- The process includes technical IRP sessions, open to all stakeholders, to allow for additional expert input on specific topics, beyond what may be provided in public meetings.
- Technical experts have access to review all inputs, outputs, modeling files and can gain access to the modeling software the utilities used (as discussed in Best Practice 2).

If utilities are unable to meet any of these elements, they can make appropriate efforts to retroactively ensure stakeholders have an opportunity to give productive input.

There are many examples of public utility commissions and utilities implementing the practices noted above. For instance, in 2022 the New Mexico Public Regulation Commission established new rules that promote engagement and transparency in IRP processes for the state's investor-owned electric utilities. The rules require the utilities to use a facilitated stakeholder process and provide stakeholders with reasonable access to modeling software, perform a reasonable number of modeling runs, and share all modeling information (Gridworks 2024).

As another example, in 2018 the Hawaii Public Utilities Commission ordered Hawaiian Electric Companies to develop a workplan that comprehensively describes the timing and scope of major activities that will occur in the integrated grid planning (IGP) process (HI PUC 2018). The workplan describes the following: (1) the proposed working groups, including specific objectives, composition, expected deliverables, and timelines; (2) a proposal for how forecasting assumptions, system data, modeling inputs, studies, analyses, meeting summaries, and other data will be shared with the PUC and community members throughout the IGP process; (3) processes and timelines to define and quantify system needs; (4) processes and timelines to procure solutions to meet grid needs and to optimize the solutions; (5) opportunities for midstream evaluation and updates; and (6) the role of independent facilitation in assisting the IGP process.

[5] As discussed in Section VI, a utility identifies a preferred portfolio after reviewing the results of the modeling analysis. This collection of resource builds and retirements reflects the utility's short- and long-term resource plans.
[6] IRPs provide a framework to inform utility resource solicitations and specific resource commitments. Overuse of protective agreements and redactions in an IRP can hinder stakeholder engagement in those processes.

Best Practice 2. Engage technical stakeholders in IRP modeling

Provide modeling files and other necessary information to technical stakeholders to allow them to replicate modeling outcomes from the IRP and develop alternative portfolios.

Utility IRP modeling is generally conducted using sophisticated and proprietary capacity expansion and production cost modeling software. The software is largely inaccessible to stakeholders, challenging their role in supporting regulatory oversight. Often, PUC staff are not trained in utility modeling software, so they cannot ensure that utilities conducted modeling reasonably and prudently. However, technical stakeholders with modeling expertise and access to data can verify and validate utility outcomes and findings. They can independently test utility assumptions, identify refinements and improvements, and bring additional technical knowledge to IRP proceedings. Such contributions by stakeholders are valuable even in states where PUC staff are more engaged in IRP modeling. Stakeholders can also model alternative portfolios that use the same, or a similar, modeling framework as the utility. The commission would not have such information in the absence of technical intervenor participation.

The following is necessary to enable technical intervenors to participate in the modeling process:

- Modeling software licenses, paid for by the utility, for all technically sophisticated stakeholders with the ability to review the modeling files or perform their own modeling runs
- Input data, model settings and constraints, and output data for the reference portfolio and preferred portfolio as well as all major scenarios presented in the IRP
- Modeling files and data that match what the utility is using so that intervenors are able to replicate the utility's modeling outcomes as a starting point and calibration step for their own modeling exercises
- Explanations of how the utility used input data and values, how it derived inputs, and what steps the utility took to develop portfolios and results
- Utility spreadsheets used for pre-processing of data and post-processing of results so stakeholders can see any modifications used to develop model input streams and convert outputs to revenue requirement results
- Documentation for supplemental analysis the utility used to develop inputs, such as reserve margin or effective load-carrying capability (ELCC), that it developed externally or outside the model.

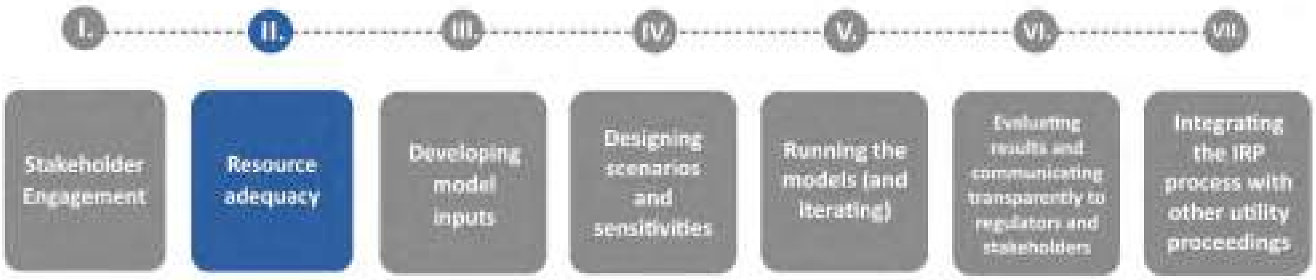
Definition: Effective load carrying capability

The ELCC of a resource or portfolio of resources represents the amount of dependable capacity the resource can provide.

For example, as part of the Arizona Public Service (APS) 2023 IRP process, the commission required the utility to provide intervenors with licenses for the Aurora model, utility modeling files, and trainings with the model developer as well as access to resources (ACC 2022). This allowed stakeholders to carry out their own modeling.[7] In Iowa, as part of two settlement agreements, MidAmerican Energy Company and Interstate Power and Light agreed to provide intervenors with model licenses as part of the Renewable Energy Study docket (MEC 2022). In Michigan, DTE and Consumers Energy also agreed voluntarily to provide modeling licenses to stakeholders as part of the IRP process.

[7] However, the utility did not provide the modeling files for all of its scenarios, limiting stakeholders' ability to validate the company's modeling results for its preferred portfolio and scenarios.

II. Resource adequacy



IRP capacity expansion models are designed to optimize resource build and retirement decisions while maintaining an acceptable level of system reliability and meeting policy requirements. These models typically represent system reliability using a planning reserve margin, which denotes the energy capacity in excess of the forecasted peak load that the utility needs to serve in order to maintain the desired level of reliability. The required reserve margin creates a buffer to protect the system from load forecasting uncertainty and factors that could unexpectedly influence supply or demand. Such factors include unplanned unit outages, generation or transmission contingencies affecting energy supply, and extreme weather events.

Traditionally, resource planners used an annual planning reserve margin and designed their systems to ensure that they could meet demand on the single annual hour of peak demand. Planners would calculate the annual planning reserve margin necessary to achieve target levels of system outages and calculate a firm capacity rating for each resource based on its expected availability at peak. Then, they would run their capacity expansion model to optimize resource build and retirement decisions based on the annual planning reserve margin constraints. There was limited iteration.

This construct worked relatively well when resource availability[8] was relatively uniform year-round,[9] nearly all system resources were dispatchable, and peak demand was substantially larger during one season. But planners can no longer universally assume any of these things to be true, particularly as renewable energy sources and storage make up a larger portion of the resource mix. Planning for times with low resource availability can be as important as planning for times with peak system demand. This planning is most effectively done by evaluating system needs and resource contributions through a coordinated and iterative resource adequacy assessment.

Resource adequacy is defined by Electric Power Research Institute (EPRI) as an assessment of whether the current, or projected, resource mix is sufficient to meet capacity and energy needs for a particular grid (EPRI n.d.). Validation of resource adequacy is a critical and integral part of resource planning. Ultimately, best practices in resource adequacy are not about developing robust static metrics, but rather developing an iterative process for establishing system need, valuing resource contribution to system

[8] Here we refer to resource availability generally as the megawatts (MW) of capacity a resource can provide to the grid based on its own inherent characteristics and limitations, as well as external conditions that impact operations.
[9] With small deviations for steam unit performance based on temperature.

need, and testing how well a resulting portfolio meets system needs. However, in the absence of an iterative modeling process, development of a robust reserve margin is essential.

This section of the report introduces foundational best practices for addressing resource adequacy in IRPs. Recognizing the complexity of the issue, the variety of approaches available, and work by many others in the field, we recommend that resource planners use our best practices as a baseline and screen. Figure 5 provides resources (linked) developed by Energy Systems Integration Group (ESIG), EPRI, and other leading experts in the field that offer more detailed discussion on resource adequacy principles and specific implementation guidance.

Figure 5. Resources on resource adequacy principles and specific implementation guidance—click to view

- Linking Capacity Expansion, Resource Adequacy, and Production Cost Modeling Tools for Integrated Strategic System Planning. (Electric Power Research Institute 2024)
- Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. (Energy Systems Integration Group 2023)
- New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements. (Energy Systems Integration Group 2024)
- Redefining Resource Adequacy for Modern Power Systems. A Report of the Redefining Resource Adequacy Task Force. (Energy Systems Integration Group 2021)
- Lawrence Berkeley National Laboratory: A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems. (Carvallo et al. 2023)

We discuss three best practices in this guide related to resource adequacy: (1) integrating resource adequacy analysis, resource planning analysis, and development of robust reserve margins; (2) aligning resource accreditation with realistic expectations of resource availability and applying constructs uniformly across resource types; and (3) taking a regional perspective on resource adequacy.

Looking Ahead: Link frameworks for developing reserve margins and resource capacity accreditation

Looking to the future, the framework for developing the reserve margin and the framework for calculating resource capacity accreditation need to evolve together, as the two are inherently linked.

EXHIBIT 67
Part 2
(Pages 16–29)

Best Practice 3. Link resource adequacy assessments with resource planning

Conduct resource adequacy assessments and resource planning analysis in a coordinated and iterative manner.

Linking resource adequacy assessments with resource planning in an iterative manner generally starts with stochastic modeling[10] to develop a reserve margin that reflects reliability standards and requirements and preferences.[11] Planners then use the reserve margin in the resource planning model to develop an optimized resource plan. The resulting resource plan is then tested in the resource adequacy model to ensure that the plan still meets system reliability requirements, or that it does not exceed them significantly (since overly adequate systems have higher cost). Iterations continue on the reserve margin and resource portfolio until the modeling develops an optimized resource plan that meets the reliability standard. In practice, it is not essential to develop a precise reserve margin when resource adequacy modeling is being used to validate portfolio performance. In such cases, utilities can choose a reasonable starting value and iterate as necessary.

In PNM's 2020 IRP, for example, the utility used SERVM to develop the planning reserve margin requirement needed to meet a loss-of-load expectation (LOLE) standard of 0.2 days per year as well as to validate that the IRP portfolios met or exceeded this resource adequacy standard (E3 and Astrape 2022). While this type of iterative modeling is the best practice, it is time- and resource-intensive. For IRP processes that do not use resource adequacy modeling to validate portfolio performance, development of a robust reserve margin upfront is essential.

Planners typically calculate reserve margins and other resource adequacy metrics through separate modeling exercises conducted prior to IRP modeling. Utilities operating outside of centrally organized wholesale electricity markets are responsible for calculating their own resource adequacy metrics. In regions with organized regional transmission operator (RTO) or independent system operator (ISO) markets, the grid operator generally conducts extensive resource adequacy analysis, and utilities adopt the RTO or ISO values rather than conduct their own analysis. In the Midcontinent Independent System Operator (MISO) market, for example, the market operator released a seasonal capacity accreditation framework applicable to all utilities within the market. Utilities such as Ameren Missouri internalize MISO's planning reserve margin (Ameren Missouri 2023b).

Critically, planning reserve margin and capacity accreditation frameworks need synchronization. If the utility is using a reserve margin differentiated by season, it must also value the capacity accreditation of resources differently by season. Calculations of capacity accreditation values for individual resources occur through similar, but separate, resource adequacy analysis (as discussed in detail in the next section). The framework for developing the planning reserve margin and the framework for calculating resource capacity accreditation ultimately need to evolve together, as the two are inherently linked.

[10] Stochastic modeling accounts for uncertainty by performing a range of simulated futures and accounting for the probability of that future occurring.

[11] Reserve margins are developed to achieve a reliability benchmark, such as a maximum number of expected hours with outages per year (e.g., a 1-day-in-10-years loss of load expectation).

Planners conduct reliability analysis using stochastic techniques coupled with Monte Carlo analysis[12] to determine how a given reserve margin, portfolio, or resource meets reliability requirements. Stochastic analysis relies on large quantities of weather data that contains both normal and extreme weather events to test performance under a wide range of circumstances. Typically, planners use historical data, although some utilities are switching to use climate change forecast data instead.[13] There are limitations for planners to consider when using historical data for calibration and characterizing stress events, due to increased frequency and severity of extreme weather events as well as accelerating electrification, manufacturing, and data center loads—which may not be reflected in historical load. Forward-looking, synthetic data also has limitations, mainly related to availability and judging its veracity. An example of a utility that has conducted a separate, stochastic modeling study to develop a planning reserve margin and assess resource adequacy is Public Service Company of Colorado (Astrapé Consulting 2021).

Resource adequacy analysis can test variations in a discrete number of factors such as load and outage rates. Modeling runs typically focus on a single study year at a time and identify the time periods with the highest LOLE. The resulting hundreds to thousands of iterations for each study year determine the likely performance of an entire system with a given portfolio. The required planning reserve margin may differ by year based on the available capacity mix from utility-owned and -procured resources, as well as from the market, and the outage rates of capacity resources for that given year, for example. Because a utility conducts resource adequacy analysis for a single study year, when it is validating the resource adequacy performance of a portfolio, it would ideally repeat the modeling for years in which the utility expects large changes in the system. Some utilities perform the additional step of evaluating the cost to the system of different reserve margin levels above the minimum required to achieve the reliability target (such as the 1-in-10-year LOLE). For example, Georgia Power included an economic and reliability study of the target reserve margin as part of its 2022 IRP filing (GPC 2022).

Best Practice 4. Apply consistent accreditation frameworks to all resource types

Credit all resource types in a fair and consistent manner, and clearly align reliability modeling with realistic expectations of resource availability.

The current best practice for capacity accreditation is to use stochastic modeling to conduct an ELCC study for each resource type. A consistent methodology to accredit resources can ensure all resource types are treated in a fair and non-discriminatory manner. The ELCC of a resource represents the amount of incremental dependable capacity the resource can provide to the system. The first step is evaluating how much additional load can be served on the utility system with the addition of a set quantity of a specific resource type, while maintaining the same level of reliability. Planners then calculate the ELCC by dividing incremental peak load served by the nameplate capacity of the added resource. The result is a marginal ELCC which reflects the incremental capacity contribution of the next megawatt of a given resource and an average ELCC which measures the aggregate or portfolio reliability impact of the

[12] Monte Carlo is an analysis technique used to predict the probability of different possible outcomes in the face of uncertainty. The analysis uses historical data to predict a range of future outcomes.
[13] Historical data is likely still the best source for calibration purposes, but it is important to be aware of its limitations.

resource across all megawatts (not just the next megawatt) or across a specific tranche of capacity. ELCC studies are complex, data- and time-intensive, and resource-specific. As discussed above, many RTOs and ISOs conduct their own ELCC studies which utilities can, and sometimes even must, apply to their own footprints (LBNL 2021b). Utilities that do not operate in RTO/ISO regions generally perform ELCC analysis in a modeling exercise separate from the IRP process.

Some utilities do not have time or resources to conduct their own studies for every resource considered. It is critical to avoid over-simplified assumptions that systematically disadvantage certain resource types. For example, if the utility performs a study of the ELCC for a 4-hour battery energy storage system, it cannot assume that the ELCC for an 8-hour system would be the same. Instead, the utility can look to studies from regionally comparable utilities and rely on their calculations, with reasonable and well-justified and documented adjustments as necessary, to account for differences across the utilities.

It is critical for utilities to avoid over-simplified assumptions that systematically disadvantage certain resource types.

Over the past decade, there has been considerable attention on calculating the ELCC for wind and solar and battery energy storage systems (BESS). There has been more limited attention on whether the traditional methods still used to value firm capacity for conventional thermal resources (such as coal, gas, or oil) — the Equivalent Forced Outage Rate Demand, or EFORd, methodologies — still result in sufficient resource adequacy. As the grid evolves, these traditional methods will not be sufficient.

EFORd-based methodologies value a resource's capacity based on the unit's historical outage rates at times it was needed. This means that modeling of fossil fuel resources usually uses average forced outage rates rather than weather-dependent forced outage rates, underrepresenting outage risk in periods of extreme weather. Recent high-profile extreme weather events, including Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, highlight the risks of availability of traditional fossil fuel resources and correlated outages within a given power class of assets (e.g., natural gas) not captured by traditional capacity accreditation methodologies (S. Murphy, Sowell, and Apt 2019). These traditional methodologies (generally determined by RTOs) systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent by failing to account for outage variability, correlated outages, weather-dependent outages, and fuel supply constraints (AEE 2022; Astrapé Consulting 2022).

When viewed together, the use of the EFORd method for thermal resources and ELCC method for wind and solar is concerning:

- The EFORd methodology over-accredits capacity value for thermal resources.
- Utility customers are therefore paying for some level of capacity and reliability services from thermal resources that they do not actually provide.
- Wind and solar resources are being held to a higher standard with the ELCC methodology, resulting in systematic discrimination against them.

Traditional capacity accreditation methodologies have been found to systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent.

As discussed above, the best practice is to apply the same accreditation methodology to all resources. In this case, that is using the ELCC methodology to calculate firm capacity for all resources, including thermal resources. PJM, the ISO/RTO for the mid-Atlantic region, is following that principle.

If ELCC analysis is not available, an alternative is to develop downward adjustments to EFORd-based capacity ratings using actual unit performance during historical scarcity hours. These adjustments can account for undercounted outage risks, including fuel supply contracts, unit age, and extreme weather risks. Additionally, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Using more accurate thermal capacity accreditation increases system resource adequacy by realigning incentives for utilities to improve the outage rates of thermal resources while addressing the systematic disadvantage faced by wind and solar resources.

Best Practice 5. Use a regional perspective to plan for resource adequacy

Align resource adequacy and resource planning with the larger region and market, when applicable, to more accurately capture regional interactions and impacts.

Resource adequacy planning requires a regional perspective to ensure requirements are sufficient without being overly conservative and unnecessarily costly. Utilities that operate within regional markets generally align their reserve margin construct and resource accreditation framework with methods used by the market operators. For utilities not in an RTO, the best option is using resource adequacy studies for the larger region in which the utility operates (e.g., Puget Sound Energy and PNM). Modeling a utility footprint as an island may simplify the modeling exercise, but it is an overly conservative approach that undermines the resource adequacy and portfolio contributions of market transactions (LBNL 2019b) and regional resource diversity.

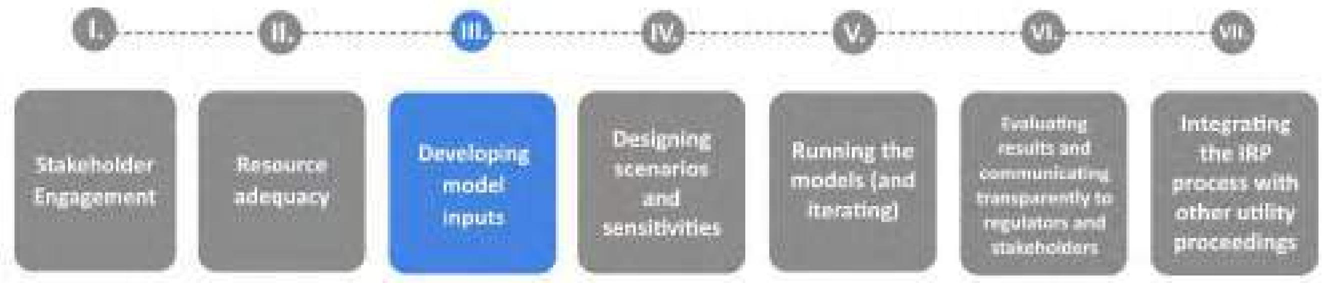
Utilities operating outside RTO/ISO regions, such as those that operate in the Southeast and Western United States, can capture regional benefits by modeling their utility footprint within the larger region in which they operate. This can include reasonable assumptions around the role of market transactions (energy and capacity) based on a realistic view of current procurement in the near term (i.e., how much the utility currently relies on the market) and likely future resource availability later in the study period. To capture the reliability impacts of resource diversity–for example, to understand how wind resources in the larger region can complement solar within the utility footprint–the utility needs up-to-date data on resource plans for other regional utilities. To address uncertainty in both market availability and regional resource development, a best practice is for utilities to model multiple future scenarios that capture different levels of future regional cooperation and resource deployment.

For utilities that operate within an RTO or ISO, market operators conduct resource adequacy evaluations that are inherently regional in scope. Market operators have a variety of unique approaches to address resource adequacy:

- After several years of development, MISO adopted a four-season capacity accreditation construct that breaks down system capacity needs into four time periods during the year.
- PJM recently proposed, and FERC approved, an overhaul of its capacity market. This change increases the accuracy of PJM's accreditation frameworks through the use of marginal ELCC calculations for all resources (new and existing, fossil fuel and renewable), providing greater confidence in reserve margin calculations (FERC ER24-99 n.d.).
- In California, three agencies—the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), and California Energy Commission—have developed a collaborative institutional relationship to ensure that utility-scale resource planning aligns with regional assumptions. CPUC requires load-serving entities such as utilities with loads greater than 700 gigawatt-hours (GWh) to perform IRP processes that adhere to resource adequacy requirements at the state (and ISO/RTO) level. CPUC then reviews the portfolios of each load-serving entity and develops a statewide IRP and preferred portfolio, which is a key input into CAISO's regional transmission planning and regional reliability modeling (CPUC 2016).
- Utilities outside California operating in the Western Interconnect do not have an ISO or RTO. The utilities individually develop reserve margins based on their own analysis of what they need to meet LOLE. The Western Electricity Coordinating Council (WECC) conducts resource adequacy assessments (WECC n.d.) to help these utilities better understand their regional resource adequacy position. Also, many entities in the Western Interconnect are participating in the development of the Western Resource Adequacy Program (WRAP), which assigns planning reserve margins to participants based on regional resource adequacy needs.[14] Additionally, the Southwest Power Pool is pursuing options to expand full regional transmission services to some utilities in the Western Interconnect, and a stakeholder initiative is underway to evaluate what governance and programmatic changes could promote future expansion of CAISO.

[14] WRAP is developing a regional reliability planning and compliance program for Western states to assess and address resource adequacy (Western Powerpool 2023).

III. Developing model inputs



After selecting the appropriate modeling tools and evaluating reliability constraints, planners develop other critical model inputs. Developing input assumptions is ideally an iterative process as subsequent steps of the IRP process reveal new information or guidance. The following best practices guide planners through the various input assumptions, such as load forecasts, demand-side and supply-side resources, and transmission.

Best Practice 6 and Best Practice 7 provide general guidance on developing model inputs. Best Practice 8 through Best Practice 11 discuss load inputs and how to model the changing nature of electric sector demand. Best Practice 12 through Best Practice 18 discuss a wide array of practices and issues associated with supply-side resource modeling. Best Practice 19 through Best Practice 22 discuss how to incorporate energy efficiency and other demand-side resources in IRP modeling. Best Practice 23 provides guidance on modeling market purchases. Best Practice 24 and Best Practice 25 discuss fuel and commodity inputs. Best Practice 26 and Best Practice 27 address transmission modeling inputs.

Best Practice 6. Use up-to-date inputs and assumptions

Use inputs that reflect the most recent available knowledge, grounded in the most recent available historical data and utility-specific studies.

Best practice is to use inputs that reflect the most recent available knowledge, without over-relying on emerging trends that can distort inputs. The typical frequency of IRP filings every 2 to 4 years requires balancing up-to-date inputs with minimizing risks from overstating near-term trends.

A key challenge to using up-to-date inputs and assumptions is planning variables that change while the IRP is under development and forecasts have already been produced and potentially implemented. Rather than continue to rely on a forecast that is directionally wrong (and depending on the stage of the IRP process), an effective IRP process develops a new forecast, waits for development of a new external forecast, or runs a sensitivity analysis using an existing forecast that best represents the current situation. Utilities are not expected to update their models during the IRP process every time something changes. If they did, they would never finish the exercise. Instead, utilities can acknowledge when a change (e.g., commodity or electricity market prices) is significant enough to render modeling results less applicable. If the utility is already too far into the planning process to update base assumptions, best practice is to add sensitivities or scenarios to capture the change (see Best Practice 28 through Best

Practice 30). When significant changes occur, the relative cost of performing additional IRP modeling is minute compared to the scale of investments informed by additional modeling. For example, if an unexpected market condition would lead to reduced natural gas supply and increase in prices, a high short- to medium-term natural gas price sensitivity would be a good option.

Utilities following best practices carefully avoid extrapolating short-term trends over a longer-term period where such assumptions are unsupported. For example, recent supply chain and inflationary pressures resulting from the COVID-19 pandemic caused prices of renewable energy and battery technologies to increase, interrupting a decade of price declines. Some industry sources project this will be a short-term trend and prices will return to previous declining trends (NREL ATB 2024). Yet some utilities have applied this current situation to adopt overly conservative cost decline assumptions for new resources for the entire 10- to 20-year IRP study period (Entergy Arkansas 2024). Adopting conservative cost decline assumptions for all resource types biases modeling results against renewable energy resources, which still are expected to experience technological advances and cost declines relative to more established, conventional technologies. This example illustrates the importance of grounding all assumptions in industry trends and real-world data. When circumstances change, best practice is to add new sensitivities or scenarios to capture the change.

In contrast to temporary price distortions due the recent pandemic, the passage of the IRA provides lasting opportunities that most utilities are just beginning to incorporate into IRPs. According to RMI, of the 50 utilities that filed planning documents between the passage of the IRA and January 2024, “32 percent failed to include IRA provisions in their models, and none adequately considered the IRA’s benefits and implications for their systems” (RMI 2024b). It has taken time for the Internal Revenue Service to offer guidance on implementation of many aspects of the IRA, and guidance is still being released (U.S. IRS n.d.). However, many aspects of the IRA that affect fundamental inputs to IRP are now clear and can be internalized in IRP modeling. These include extended and expanded investment and production tax credits for zero-carbon resources and storage, tax credit adders for domestic content and project locations in energy communities,[15] and tax credits for clean hydrogen and carbon capture and storage (CCS).

A final element of this best practice is the treatment of input data that relies on historical records, such as weather data, to train weather-sensitive models or to run resource adequacy assessments. For example, in its 2021 Northwest Power Plan, the Northwest Power and Conservation Council states that the historical weather record does not reflect future weather patterns induced by a changing climate (Northwest Council 2022). The plan implements modeled climate change projections that complement historical data, giving more weight to recent years in the historical record without disregarding the historical variability of weather patterns. PJM’s 2023 effort to reform resource accreditation of its capacity market provides another example. PJM explained that its preference was to extend the historical weather data used to calculate gas unit ELCC to between 30 and 50 years, and to use unit operational data from 2012 to the present(PJM Proposal 2023a; Update 2023c; PJM FERC 2023b). PJM

[15] U.S. DOE defines energy communities as (1) brownfield sites, (2) certain metropolitan statistical areas and non-metropolitan statistical areas based on unemployment rates (MSA/non-MSA), or (3) census tracts where a coal mine closed after 1999 or where a coal-fired electric generating unit was retired after 2009 (and directly adjoining census tracts). See https://www.irs.gov/pub/irs-drop/n-24-30.pdf.

also addressed the potential to include climate change adjustments to the historical weather data, as the Northwest Power and Conservation Council is doing.

Best Practice 7. Recognize historical data limitations

Evaluate when the past is a good predictor of the future and when the future is likely to be fundamentally different.

Historical data is useful for calibrating model inputs and sense-checking model results, yet it does not always reflect the future. An emerging example includes observed weather data that is no longer a good predictor of the future due to climate-change-induced patterns and anomalies (see Best Practice 6). Similarly, emerging changes in load composition due to new types of loads, and substitution of fuels for electricity, render load forecasts based on historical data less accurate (see Best Practice 8). Finally, historical generator performance and outage probabilities may not reflect future conditions if units are retrofitted with equipment that improves their resilience.

There are several alternatives to historical data for developing data inputs, as in Best Practice 8 on load forecasting. However, in some cases the use of historical data is needed because it is challenging to produce credible synthetic data or because the data is used in probabilistic analyses such as resource adequacy assessments that require a high volume of actual observations. In these cases, planners can ensure they prioritize the use of more recent data over older data, or conversely reduce the weight of older data that may not reflect current conditions.

A best practice to assess the usefulness of historical data is to perform retrospective analyses of key assumptions, inputs, and forecasts. In its 2021 IRP, Puget Sound Energy devoted an entire section to performing retrospective analysis of previous demand forecasts (PSE 2021). The analysis compares forecasts developed in five previous plans—going back over a decade—with realized values for the forecast variable, adjusting for weather realizations when appropriate (e.g., for the peak demand). The utility developed analyses for electric and natural gas peak demand, housing, and population growth and provided reasons for forecast deviations that could be incorporated in current forecasts. Planners can use this retrospective analysis to inform which historical data is useful on its own, adjustments needed to historical data, or whether historical data does not sufficiently inform future system performance.

LOAD INPUTS

Best Practice 8. Develop a load forecast for the expected future

Develop a load forecast that captures granular temporal and geographic detail, expected future electrification and load growth levels, and decarbonization policies—and that is aligned with current reliability modeling.

Load forecasting is a cornerstone of IRP and one of the key model inputs for production cost, capacity expansion, and reliability models. Electrification of end uses, data center development, and other emerging trends indicate that the era of flat electric load growth is over (Grid Strategies 2023). This section covers best practice in methods, granularity, and characterization of load and its flexibility, considering these trends.

In the past, utilities forecasted annual system-level energy consumption and peak demand, generally split out by customer segment (i.e., residential, commercial, industrial). System operational challenges are prompting a much more granular temporal and spatial resolution to load forecasts that supports similar developments in models (Best Practice 31, Best Practice 32, and Best Practice 33). A best practice is to develop an hourly load forecast that reflects diurnal/nocturnal needs, as well as daily, weekly, and seasonal energy consumption to support a resource portfolio with energy-limited resources such as wind and solar. Several utilities such as PacifiCorp and Puget Sound Energy develop hourly load forecasts for use in production cost models (PSE 2021; PacifiCorp 2023). Similarly, load forecasts that match the model's geographic resolution will better recognize the spatial diversity of load growth and the spatial location of load with respect to transmission infrastructure. PacifiCorp, for example, historically has produced forecasts for the west and east sides of its service territory.

Increasing load from electrification is expected to continue in the coming decades, along with growth of large new loads such as data centers and manufacturing (see Best Practice 10). Forward-looking utilities are striving to properly model electrification and load growth in IRPs to ensure there are adequate resources to meet energy needs (ESIG 2024). Planners would separately forecast three key electrification variables: (1) adoption of end uses, (2) operation of these end uses, and (3) flexibility potential of such operation. Utilities have historically developed forecasts by customer segment, a practice that can be maintained as it creates a link to the ratemaking process. At the same time, electrification and load growth require an end-use approach. End-use forecasting methods have been used for decades, separately projecting saturation (i.e., customer adoption) and usage intensity for specific residential and commercial end uses (LBNL 2018). This approach is well suited for developing transparent base case and sensitivity load forecasts for emerging end uses such as EVs and heat pumps, and to track specific load growth for data centers, manufacturing, and other industries. Traditional time series-based approaches are insufficient to adequately represent emerging trends. Econometric approaches may be used as a method to predict adoption patterns, as part of an end-use model. An emerging method is propensity of adoption, which leverages machine-learning techniques to determine likelihood of customer adoption based on a wide range of characteristics and drivers (Ratchford and Barnhart 2012). In its 2023 IRP, PacifiCorp developed a propensity of adoption model to predict behind-the-meter PV adoption.

Adoption of new types of electrified end uses and decarbonization policies are tightly linked, although in many cases electrification is an economic decision for customers. The federal government has set several important decarbonization goals, including a 2030, all-sector greenhouse gas reduction target of 50 percent relative to 2005 levels (White House 2021) and securing a 100-percent clean electrical grid by 2035 (U.S. DOE 2023a). Numerous states have promulgated greenhouse gas reduction goals that include electrification, particularly for transportation (C2ES 2024; CESA n.d.). In addition, funding available through IRA supports electrification and decarbonization across the United States (RMI 2024b). A best practice for IRPs is to internalize any state-level electrification goals or electrification impacts of decarbonization policies. An extension of this practice entails running sensitivities that meet federal electrification and decarbonization goals to show the potential impacts of these policies. For example, Public Service Company of New Mexico modeled multiple "futures" in its IRP, including a National Climate Policy future that included high EV adoption and building electrification forecasts (PNM 2023).

Finally, past IRPs have used different statistical properties to reflect variability in their load forecasts. Typically, utilities use a median or 50/50 forecast for energy consumption forecasts and a 90/10 or higher peak demand forecast. The use of a higher percentile as a peak load forecast is not consistent with best practices that link capacity expansion decisions with resource adequacy assessments that ensure the system operates under a prescribed loss of load probability. A best practice is to use median forecasts for energy and peak demand and to let the resource adequacy assessment reflect capacity needs to address stress periods in the grid (see Best Practice 3, Best Practice 4, and Best Practice 5).

Best Practice 9. Incorporate load flexibility into electrification forecasts

Characterize load flexibility operational parameters consistent with electrification forecasts.

Just as important as the magnitude of expected load growth is the shape of new power demand (NREL 2021d). This shape should reflect expected operational profiles for end uses and the flexibility potential of these operational profiles to meet one or more grid services. For example, EVs can achieve a desired state of charge using multiple charging profiles operating independently or in coordination with others. Assumptions about operational charging profiles will have differing impacts on peak load; similarly, assumptions about the willingness or ability of the EV owner to switch and adapt the EV's operational profile captures its flexibility.

Explicit modeling of EVs as a contribution to load is increasingly common, including in IRPs for Puget Sound Energy, DTE Energy, and Entergy Louisiana (PSE 2021; DTE 2022; Entergy Louisiana 2023). Notably, a large portion of this EV load is flexible especially when charging at lower voltage levels for extended periods of time. Different charging incentives can shift EV load to different times of day, and effective planners will model corresponding impacts in the IRP load forecast (Synapse 2020). NorthWestern Energy's 2023 IRP for Montana analyzes potential system and supply benefits of an EV charging management program, though the utility did not integrate the analysis directly into its planning models. Optimized EV charging can add flexibility that improves grid reliability by more effectively using renewable energy, shaving peak electricity demand, and helping maintain power quality (NREL 2021b). The same is true of distributed battery storage systems and demand response linked to newly electrified loads (NREL 2021c; NREL 2021b).

Modeling load flexibility requires using transparent assumptions from reputable studies or models that project time-based load-shifting potential.[16] Preferably, utilities perform or commission their own load flexibility studies and design programs to procure specific amounts of load flexibility identified in the studies. In its 2023 combined Clean Energy Plan and IRP (PGE 2023), for example, Portland General Electric discusses the growing role of flexible loads and describes plans to use findings from

[16] Examples include NREL's EVI-PRO EV infrastructure projection tool, which allows users to develop different load shapes for EVs (NREL EV-Pro n.d.-b) Additional resources to support load forecasting include (NREL and LBNL 2023) and (LBNL 2023b).

implementation of its virtual power plant to inform future modeling of flexible load.[17] Comprehensive IRPs specify plans to achieve the level of load flexibility included in the modeling, including near-term activities in the action plan.

Demand response has been part of IRP for decades. Load flexibility modeling described in this section, however, is an emerging practice with open questions about certain best practice elements. For example, most IRPs that examine load flexibility potential for EVs do so as part of their load forecast and internalize this potential as a load modifier, or as load forecast scenarios. An alternative approach would treat load flexibility as a resource and study it as part of market potential studies traditionally used for demand-side management (DSM) through energy efficiency and demand response programs funded by utility customers (see Best Practice 19 through Best Practice 22). How to incorporate load flexibility in resource adequacy assessments, stochastically characterize flexible end uses, and assess their effective load-carrying capability are emerging issues.

Best Practice 10. Plan ahead for large load growth

Thoughtfully model and plan for the rapid rise of data center, industrial, and manufacturing loads.

Over the past several years, data center load driven by the rise of AI, coupled with increasing manufacturing and industrial load, have become significant drivers of projected future resource needs in jurisdictions across the country, most notably in Arizona, Virginia, Georgia, and Texas (Martine Jenkins and Skok 2024). This new challenge comes as utilities are wrestling with increased load from transportation and building electrification and a changing resource mix as baseload fossil fuel units retire and carbon-free energy resources come online.

The uptick in demand represents a turning point over the previous decade when the United States experienced relatively flat to declining demand growth due in large part to increased DSM and distributed generation deployment (Grid Strategies 2023). Best practices in resource planning will be different for this new era of growth than they were during the past decade. Before utilities build or acquire new resources to meet this new load, there are actions they can take to understand the level of certainty about potential new loads, manage the impact of new loads on system peak, determine the lowest-cost way to meet new loads while maintaining system reliability, and understand the impact of new loads on utility customers and the electricity system broadly. Critically, in this new era of load, customers will be best served if utilities shift from viewing load as a static input to be served in a given year, to viewing the timing of serving load as another decision the resource plan can consider and optimize.

[17] Oregon-regulated utilities also file multi-year flexible load plans with the PUC every 2 years (OR PUC 2020).

The first step for utilities is to determine what level of data center and industrial load is likely to materialize within their service territory. There are varying views on whether future load growth projections for these sectors at large are accurate or overstated. But at the individual utility level, utilities and regulators can take specific measures to avoid building for speculative load and incurring associated costs for all customers:

- Utilities can develop rigorous methodologies for evaluating the likelihood that each potential data center and industrial customer will come online and materialize as actual load. Methods include weighing potential new customers individually based on development milestones, or requiring customers to meet construction and service commitment levels (at which there is a reasonably high level of conversion to actual load) in order to be included in load forecasts. This is especially important given that many companies are looking for the best deal for power and are shopping around their load to multiple utilities. Early-stage negotiations of basic contract terms are insufficient to assume load will materialize. This type of customer-specific load forecasting is not new; utilities have used it to account for large industrial customers in the past. And it can be refined and applied moving forward.
- Utilities can model multiple load scenarios to understand what level of new resources are needed, and which resources are most cost-effective, based on different levels of load achieving commercial operation.
- Regulatory commissions can require utilities to demonstrate that new, large-load customers have reached specific construction milestones before they permit cost recovery of new generation resources built to serve them. In states where Certificates of Public Convenience and Necessity (CPCN) or other forms of pre-approval are required for cost recovery of new assets, commissions can decline to provide pre-approval before new load customers reach certain milestones. In states where pre-approval is not required, in general rate cases the commission can deny cost recovery for assets built to serve new load prior to the load reaching specific milestones. Commissions can also take other measures such as requesting that utilities perform modeling runs with load forecasts that remove speculative load.

The second step is for a utility to determine the timeframe over which it can reasonably meet new load and how it will serve and manage that load. While utilities have an obligation to serve customers within their service territory, they do not have an obligation to do so on a specific timeframe or with a given set of resources. A utility's obligation is to serve load in a way that manages system costs and maintains system reliability. Utilities can use multiple tools to:

- *Manage load temporally through demand flexibility.* While some data center load is relatively flat and has a high load factor (and therefore has minimal potential for temporal management), other new load offers opportunities for energy efficiency and demand flexibility. For customers with temporal flexibility, utilities can offer tariffs and DSM programs that incentivize customers to reduce usage when demand and prices are highest (RMI 2024a).
- *Manage load geographically by incenting utilities to site in certain locations.* Utilities with access to surplus generation or high penetrations of low marginal cost resources (such as wind) can offer tariffs that incentivize companies to locate in their geographic region. Utilities with more

limited access to low marginal cost resources can set tariffs that disincentivize location in their region.

- *Set a timeline for serving new load that minimizes total system costs.* Utilities can assess the timeline for new projected load connection in conjunction with the changing cost of adding new generation resources and grid-enhancing technologies over time. Rather than viewing load as a given in a specific year, utilities can view the timing of load connection as another factor to consider in minimizing system costs. If a new customer wants grid service within 3 years, but a 5-year timeframe may allow the utility to build new generation at a substantially lower cost to the system, that can be factored into planning for the new load.
- *Ensure that resources used to serve new load are part of a least-cost plan.* When utilities are considering whether to retain existing fossil-fuel resources beyond previously planned retirement dates to serve load and maintain reliability, best practice is to include the full forward-going costs of maintaining the fossil fuel plants, as well as the cost to build and maintain new resources. An existing asset that requires substantial investment to sustain it is less likely to be economic than one that requires minimal near-term operations and maintenance (O&M). Analysis of the cost of reliance on existing fossil fuel resources is especially relevant given that many new data center customers have explicit 24 x 7 carbon-free energy goals (WRI 2023).
- *Incentivize customers or third parties* to (1) build dedicated resources owned by or contracted by the customer to manage load and mitigate system impacts and (2) deploy state-of-the-art measures to ensure operations are as efficient as possible. If customers can manage some of their own peak load through efficiency and on-site generation, provide their own backup power, or provide other grid services, utilities may be able to build or acquire fewer generation units and make fewer grid investments and, in return, offer lower tariffs to the new load customers.[18]

The third step, to be conducted in tandem with the second step, is for utilities and new large-load customers to understand how new load impacts total system cost and cost allocation. While these issues have traditionally been addressed in rate cases outside of the IRP process, information about how new load will impact total system costs and cost allocation can be important in helping new customers decide where to locate, when to begin construction, and whether they should self-supply to manage their load. Analysis of how new load impacts system costs overall and individual customer classes specifically will help utilities manage cost increases and cost-shifting resulting from new load.

Finally, states can consider measures to address the pace and type of new loads that locate in their jurisdiction. While some new loads may bring economic benefits such as jobs and tax revenue, others—such as bit-coin mining—are more likely to increase electricity system costs while bringing few jobs.

[18] While these recommendations focus on actions that utilities and commissions can take to manage new load, measures and mandates can also come from the state legislature. These fall outside the scope of this guide.

Best Practice 11. Transparently represent distributed generation and storage

Develop forecasts of distributed generation and storage adoption and incorporate them into the modeling process.

Historically, IRPs have focused demand-side resource analysis on energy efficiency and demand response. Many states set up utility customer programs to encourage adoption of these demand-side measures across market segments and income groups. Even with higher levels of distributed PV and storage adoption that may prompt revisiting the scope of demand-side resources in IRP, the relative lack of focus on PV and storage remains true. For example, Arizona Public Service has one of the highest levels of distributed PV penetration in the country and its demand-side resource analysis remains focused on energy efficiency and demand response (see more on Best Practice 19 through Best Practice 22). However, planners still need to forecast adoption of distributed resources that help meet load needs and potentially defer T&D investments. In general, this analysis appears as part of the load forecast section in IRPs and is treated as a load modifier, so it is netted out of the load forecast. Duke Energy Indiana's 2021 IRP is an example of this approach (DEI 2021).

Customer-sited distributed generation and storage, community solar, and utility-owned distributed resources require different approaches. This stems largely from (1) with how much notice the utility has about deployment and operation of these resources and (2) the compensation mechanisms for these resources that inform adoption and operation. As with end uses, best practice is to forecast or simulate adoption and operation of distributed resources separately.

Planners typically forecast adoption of customer-sited resources through a linear regression that relies on current adoption trends and expected payback. Best practice is to use a propensity of adoption method that captures expected changes in customer preference, regulations, and policies. Portland General Electric and Puget Sound Energy leveraged the National Renewable Energy Laboratory's (NREL) dGen tool (NREL dGen n.d.-a) in their latest IRPs to forecast customer adoption using a propensity of adoption approach (PGE 2023; PSE 2021). In contrast, Duke Energy Indiana implements a linear regression method based on the Itron MetrixND platform (Itron, n.d.; DEI 2021). For community solar adoption forecasts, planners can look to existing support programs, which typically have adoption caps. Utility-sited resources can be retrieved from the utility's distribution system plans (see Best Practice 47).

Operation of resources depends in part on whether they are dispatchable. Operation of customer-owned distributed resources are best modeled at an hourly basis and compared against hourly load profiles for each customer segment in order to estimate net metering or net billing credits when relevant. For example, Duke Energy Indiana uses 20-year irradiance data to simulate rooftop solar production for selected locations within its service territory and produces a typical day hourly generation profile for each month of the year. Customer-owned distributed storage requires elaborate methods to forecast dispatch and determine contributions to the grid. Given its relatively low adoption, no clear best practice exists to model customer-owned distributed storage.

Deployment and operation of customer-owned distributed resources is heavily contingent on its economics, which in turn is influenced by rate structures, compensation schemes, and supporting